Chapter B3: Electricity Market Model Analysis

Introduction

The Final Section 316(b) Phase II Existing Facilities Rule applies to a subset of facilities within the electric power generation industry. However, due to interdependencies within the electric power market, direct impacts on in-scope facilities may result in indirect impacts throughout the industry. Direct impacts on plants subject to the rule may include changes in capacity utilization, generation, and profitability. Potential indirect impacts on the electric power industry may include changes to the generation and revenue of facilities and firms not subject to the rule, changes to bulk system reliability, and regional and national impacts such as changes in the price of electricity and the construction of new generating capacity.

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EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting the Final Section 316(b) Phase II Rule. The model addresses the interdependencies within the electric power market and accounts for both direct and indirect impacts of regulatory actions. EPA used the model to analyze two potential effects of the final rule and other regulatory options: (1) potential energy effects at the national and regional levels, as required by Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use");[1] and (2) potential economic impacts on in-scope facilities.

The final rule was evaluated under two electricity demand growth assumptions: The first scenario uses EPA's electricity demand assumptions. Under this scenario, demand for electricity is based on the Annual Energy Outlook (AEO) 2001 forecast adjusted to account for efficiency improvements not factored into AEO's projections of electricity sales. The second scenario uses the unadjusted electricity demand from the AEO 2001. Section B3-4 presents the results of the IPM analysis for the final rule under EPA's assumptions. Appendix A presents the results of the IPM analysis for the final rule under the unadjusted AEO assumptions. The appendix also presents a comparison of the results under the two alternative scenarios.

B3-1 Summary Comparison of Energy Market Models

EPA conducted research to identify models suitable for analysis of environmental policies that affect the electric power industry. Through a review of forecasting studies and interviews with industry professionals, EPA identified three potential models and considered each for the analyses in support of the Phase II rule: (1) the Department of Energy's National Energy Modeling System (NEMS), (2) the Department of Energy's Policy Office Electricity Modeling System (POEMS), and (3) ICF Consulting's Integrated Planning Model (IPM). These models are widely used in the analysis of various issues related to public policies affecting the electric power generation industry and have been reviewed.[2]

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[1] Please refer to Section B6-7 for a discussion of this analysis.

[2] EPA also considered other models that are more commonly used for private sector analyses but decided to focus its model selection process on models developed for public policy analyses.

The three models considered by EPA were developed to meet the specific needs of different users; they therefore differ in terms of structure and functionality. EPA established a set of modeling and logistical criteria to select the model that is best suited for the analysis of section 316(b) regulatory options. Modeling criteria refer to the models' technical capabilities that are required to provide the outputs necessary for the analysis of the section 316(b) regulation. They include the following:

- ***Redefining model plants*** – The energy market models considered by EPA aggregate similar generating units into model plants to reduce the amount of time required to run the model. However, such an aggregation is usable only if the aggregated units are similar in the base case and also have similar compliance requirements under the analyzed policy cases. The Phase II compliance requirements of in-scope facilities are based on the location, design, construction, and capacity of their cooling water intake structures (CWIS). In contrast, the existing aggregation of these models is based on factors including unit age, unit type, fuel type, capacity, and operating costs. Therefore, the model used for the Phase II analysis had to be able to accommodate a different aggregation scheme for model plants or even to run all in-scope facilities as separate model plants.

- ***Predicting the economic retirement of generating capacity*** – Compliance with Phase II regulation may increase the capital and operating costs of some facilities to a point where it is no longer economically profitable to operate the facility, or one or more of its generating units. The economically sound decision for a firm owning such a facility or unit would be to retire the facility or unit rather than comply with the regulation. Therefore, the model needed to have the ability to project early retirements as a result of compliance with section 316(b) regulation and the market's response to such closures, including increased capacity additions or increased market prices. In addition, to support EPA's economic impact analysis, the model had to be able to map early retirements to specific facilities or units.

- ***Representing the impact of structural changes to the industry from deregulation*** – Assumptions regarding deregulation of the electric utility industry could impact a model's ability to accurately depict the profit maximizing decisions of firms. Deregulation of the wholesale market for electricity is expected to reduce wholesale prices as competition in markets increases. These changes may impact decisions regarding the retirement of existing generating units, investment in new generating units, and technology and fuel choices for new generation capacity. Therefore, it was necessary for the market model to reflect the most recent trends in the deregulation of wholesale energy markets.

EPA also considered a number of logistical criteria to determine the most appropriate model for the analyses of the Phase II rule. While a given model may be desirable from an analytical perspective, its use may be restricted due to other limitations unrelated to the model's capabilities. The logistical criteria used to evaluate each model refer to administrative issues and include the following:

- ***Availability of the model*** – Due to the tight regulatory schedule of the Phase II rule, the model selected for this analysis had to be accessible at the time data inputs were available, and had to be able to turn around the analyses in a relatively short period of time. Some of the models considered for this analysis are used to conduct analyses in support of annual reports. Such requirements may limit access to the model and the staff required to execute the model, and therefore prevent the use of the model for this analysis.

- ***Sufficient documentation of methods and assumptions*** – Sufficient documentation of the model structure and assumptions was required to allow for the necessary review of results and procedure. While it may not be possible to disclose specific details of the structure and function of a model, a general discussion of the mechanics of the model, its assumptions, inputs, and results was required to make a model useable for this analysis.

- ***Cost –*** EPA considered the cost of using each model together with each model's ability to satisfy the other modeling and logistical criteria in determining the most appropriate model for the analysis of this rule. The model had to be sufficiently robust with respect to the other criteria while remaining within the budget constraints for this analysis.

EPA assessed each market model with respect to the aforementioned modeling and logistical criteria and determined that the IPM was best suited for the Phase II analysis.[3] A principal strength of the IPM as compared to other models is the ability to evaluate impacts to specific facilities subject to this rule. Another important advantage of the IPM is that it has a history of prior use by EPA. The Agency has successfully used the IPM in support of a number of major air rules. Finally, the IPM model has been reviewed and approved by the Office of Management and Budget (OMB).

[3] Please see Section B3-A.1 of the appendix to this chapter for a comparison of the three electricity market models considered for this analysis.

B3-2 INTEGRATED PLANNING MODEL OVERVIEW

This section presents a general overview of the capabilities of the IPM, including a discussion of the modeling methodology, the specification of the model for the section 316(b) analysis, and model inputs and outputs.

When the analyses in support of the Phase II proposal and Notice of Data Availability (NODA) were developed, the latest EPA specification of the U.S. power market, "EPA Base Case 2000," was based on IPM Version 2.1. In July 2003 a new version of the model, Version 2.1.6, was released. However, the tight promulgation schedule made it impossible for EPA to switch to the newer version for the analyses in support of this final rule. The analyses presented in this chapter, and the appendix, are therefore based on the specifications for the EPA Base Case 2000.

B3-2.1 Modeling Methodology

a. General framework

The IPM is an engineering-economic optimization model of the electric power industry, which generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. The model can be used to analyze a wide range of electric power market issues at the plant, regional, and national levels. In the past, applications of the IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

The IPM uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand-supply equilibrium on a seasonal basis and by region. The model seeks the optimal solution to an "objective function," which is a linear equation equal to the present value of the sum of all capital costs, fixed and variable operation and maintenance (O&M) costs, and fuel costs. The objective function is minimized subject to a series of user-defined supply and demand, or system operating, constraints. Supply-side constraints include capacity constraints, availability of generation resources, plant minimum operating constraints, transmission constraints, and environmental constraints. Demand-side constraints include reserve margin constraints and minimum system-wide load requirements. The optimal solution to the objective function is the least-cost mix of resources required to satisfy system wide electricity demand on a seasonal basis by region. In addition to existing capacity, the model also considers new resource investment options, including capacity expansion or repowering at existing plants as well as investment in new plants. The model selects new investments while considering interactions with fuel markets, capacity markets, power plant cost and performance characteristics, forecasts of electricity demand, reliability criteria, and other constraints. The resulting system dispatch is optimized given the resource mix, unit operating characteristics, and fuel and other costs, to achieve the most efficient use of existing and new resources available to meet demand. The model is dynamic in that it is capable of using forecasts of future conditions to make decisions for the present.[4]

b. Model plants

The model is supported by a database of boilers and electric generation units which includes all existing utility-owned generation units as well as those located at plants owned by independent power producers and cogeneration facilities that contribute capacity to the electric transmission grid. Individual generators are aggregated into model plants with similar O&M costs and specific operating characteristics including seasonal capacities, heat rates, maintenance schedules, outage rates, fuels, and transmission and distribution loss characteristics.

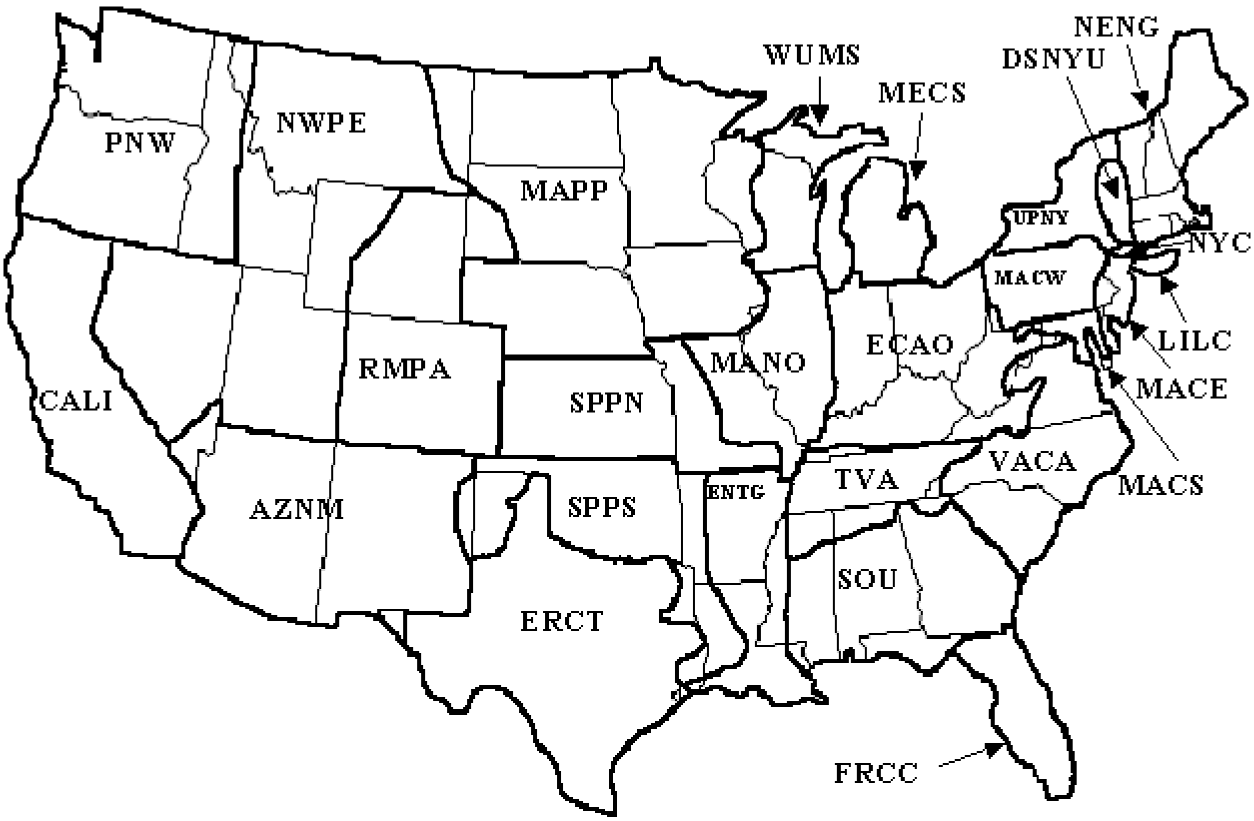
The number and aggregation scheme of model plants can be adjusted to meet the specific needs of each analysis. The EPA Base Case 2000 contains 1,390 model plants.

[4] EPA used the IPM to forecast operational changes, including changes in capacity, generation, revenues, electricity prices, and plant closures, resulting from the rule. In other policy analyses, the IPM is generally also used to determine the compliance response for each model facility. This process involves selecting the optimal response from a menu of compliance options that will result in the least-cost system dispatch and new resource investment decision. Compliance options specified by IPM may include fuel switching, repowering, pollution control retrofit, co-firing multiple fuels, dispatch adjustments, and economic retirement. EPA did not use this capability to choose the compliance responses of the facilities subject to section 316(b) regulation. Rather EPA exogenously estimated a compliance response using the costs of technologies capable of meeting the percentage reductions in impingement and entrainment required under the regulation. In the post-compliance analysis, these compliance costs were added as model inputs to the base case operating and capital costs.

c. IPM regions

The IPM divides the U.S. electric power market into 26 regions in the contiguous U.S. It does not include generators located in Alaska or Hawaii. The 26 regions map into North American Reliability Council (NERC) regions and sub-regions. The IPM models electric demand, generation, transmission, and distribution within each region and across the transmission grid that connects regions. For the analyses presented in this chapter, IPM regions were aggregated back into NERC regions. Figure B3-1 provides a map of the regions included in the IPM. Table B3-1 presents the crosswalk between NERC regions and IPM regions.

Figure B3-1: Regional Representation of U.S. Power System as Modeled in IPM



Source: U.S. EPA, 2002.

Table B3-1: Crosswalk between NERC Regions and IPM Regions

NERC Region	IPM Regions
ASCC – Alaska	Not Included
ECAR – East Central Area Reliability Coordination Agreement	ECAO, MECS
ERCOT – Electric Reliability Council of Texas	ERCT
FRCC – Florida Reliability Coordinating Council	FRCC
HI – Hawaii	Not Included
MACC – Mid Atlantic Area Council	MACE, MACS, MACW
MAIN – Mid-America Interconnect Network	MANO, WUMS
MAPP – Mid-Continent Area Power Pool	MAPP
NPCC – Northeast Power Coordination Council	DSNY, LILC, NENG, NYC, UPNY
SERC – Southeastern Electricity Reliability Council	ENTG, SOU, TVA, VACA
SPP - Southwest Power Pool	SPPN, SPPS
WSCC – Western Systems Coordinating Council	AZNM, CALI, NWPE, PNW, RMPA

Source: U.S. EPA, 2002.

d. Model run years

The IPM models the electric power market over the 26-year period 2005 to 2030. Due to the data-intensive processing procedures, the model is run for a limited number of years only. Run years are selected based on analytical requirements and the necessity to maintain a balanced choice of run years throughout the modeled time horizon. EPA selected the following run years for this analysis: 2008, 2010, and 2013.[5] The model run years were selected before the analysis in support of the proposed Phase II rule for the following reasons:

- **2008** was selected based on the assumption that all in-scope facilities would be required to comply with the requirements of the Phase II rule during the first five years after promulgation (at the time of proposal, promulgation was scheduled for August 28, 2003 so that the compliance window would have been 2004 to 2008). Therefore, in 2008, all facilities would have been in compliance, and 2008 would have represented the post-compliance state of the industry.

- **2013** was selected based on the assumption that facilities costed with a cooling tower (a requirement for some facilities under the two alternative options analyzed with the IPM at proposal) would have to comply by the end of the permit term of the first permit issued after promulgation (at the time, this was 2004 to 2012). As installation of a cooling tower may require the temporary shut-down of the facility, 2013 would have represented the first full, post-compliance year for options requiring cooling towers.

- **2010** was selected as an additional year during which facilities costed with a cooling tower may experience temporary connection outages during cooling tower installation and connection.

With the change in promulgation date from August 28, 2003 to February, 2004, EPA revised its assumptions of when facilities are likely to come into compliance with the Phase II rule from 2004-2008 to 2005-2009 (because start-up activities are required for compliance with the Phase II rule, it will no longer be possible to comply in 2004).[6] However, changing run

[5] The IPM developed output for a total of five model run years 2008, 2010, 2013, 2020, and 2026. Model run years 2020 and 2026 were specified for model balance, while run years 2008, 2010, and 2013 were selected to provide output across the compliance period. Output for 2026 was not used in this analysis.

[6] Note that compliance years 2005 to 2009 are an assumption for this analysis. The "real" compliance schedule might be different.

years requires significant structural changes to the IPM. EPA therefore decided not to change the model run years selected at proposal for this analysis. EPA mainly relied on data for 2010 in the analyses of the final rule (presented in this chapter).

The model assumes that capital investment decisions are only implemented during run years. Each model run year is mapped to several calendar years such that changes in variable costs, available capacity, and demand for electricity in the years between the run years are partially captured in the results for each model run year. Table B3-2 below identifies the model run years specified for the analysis of Phase II regulatory options, and the calendar years mapped to each.

Table B3-2: Model Run Year Mapping

Run Year	Mapped Years
2008	2005-2009
2010	2010-2012
2013	2013-2015
2020	2016-2022
2026	2023-2030

Source: IPM model specification for the Section 316(b) NODA Base Case.

B3-2.2 Specifications for the Section 316(b) Analysis

The analysis of the Final Phase II Rule (and the other regulatory options analyzed at proposal and for the NODA) required changes in the original specification of the IPM model. Specifically, the base case configuration of the model plants and model run years were revised according to the requirements of this analysis. Both modifications to the existing model specifications are discussed below.

- ***Changes in the Aggregation of Model Plants:*** As noted above, the IPM aggregates individual boilers and generators with similar cost and operational characteristics into model plants. Since the IPM model plants were initially created to support air policy analyses, the original configuration was not appropriate for the section 316(b) analysis. As a result, the steam electric generators at facilities subject to the Phase II rule were disaggregated from the existing IPM model plants and "run" as individual facilities along with the other existing model plants. This change increased the total number of model plants from 1,390 to 1,777. For the NODA and final rule analyses, EPA also disaggregated non-steam generators at Phase II facilities and generators at facilities subject to the upcoming Phase III regulation. This change increased the total number of model plants from 1,777 to 2,096.

- ***Use of Different Model Run Years:*** The original specification of the IPM's EPA Base Case 2000 uses five model run years chosen based on the requirements of various air policy analyses: 2005, 2010, 2015, 2020, and 2026. As explained above, EPA was interested in analyzing different years for the section 316(b) Phase II rule. Therefore, EPA changed the run years for the section 316(b) analysis in order to obtain model output throughout the compliance period (see discussion of run year selection in section B3-2.1.d above). The change in run years and run year mappings are summarized below.

Table B3-3: Modification of Model Run Years

EPA Base Case 2000 Specification		Section 316(b) Base Case Specification	
Run Year	**Run Year Mapping**	**Run Year**	**Run Year Mapping**
2005	2005-2007	2008	2005-2009
2010	2008-2012	2010	2010-2012
2015	2013-2017	2013	2013-2015
2020	2018-2022	2020	2016-2022
2026	2023-2030	2026	2023-2030

Source: IPM model specifications for the EPA Base Case 2000 and the Section 316(b) NODA Base Case.

EPA compared the base case results generated from the two different specifications of the IPM model. The base case results could only be compared for those run years that are common to both base cases, 2010 and 2020. This comparison identified little or no difference in the base case results:

- Base case total production costs (capital, O&M, and fuel) using the revised section 316(b) specifications do not change in 2010 and are lower by 0.1% in 2020.
- Early retirements of base case oil and gas steam capacity under the section 316(b) specifications are lower by 850 megawatt (MW). Early retirements of base case nuclear capacity decreased by 480 MW. There is no difference in the early retirement of coal capacity.
- The change in model specifications results in virtually no change in base case coal use and a 1.5 percent reduction in gas fuel use in 2010.

The IPM base case specification for the final rule is the same as the one used for the section 316(b) Phase II NODA.

B3-2.3 Model Inputs

Compliance costs and compliance-related capacity reductions are the primary model inputs in the analysis of section 316(b) regulations. EPA determined compliance costs for each of the 535 facilities subject to Phase II regulation and modeled by the IPM.[7] For each facility, compliance costs consist of capital costs (including costs for new screens or fish barrier nets, intake relocation, and intake piping modification), fixed O&M costs, variable O&M costs, permitting costs, and capacity reductions (for information on the costing methodology, see the Section 316(b) Technical Development Document; U.S. EPA, 2004).

- ***Capital cost*** inputs into the IPM are expressed as a fixed O&M cost, in dollars per kilowatt (KW) of capacity per year. The capital costs of compliance reflect the up-front cost of construction, equipment, and capital associated with the installation of required compliance technologies. The IPM uses two up-front cost values as model inputs (one each for technologies with a useful life of 10 and 30 years, respectively) and translates these values into a series of annual post-tax payments using a discount rate of 5.34 percent and a capital charge rate of 12 percent for the duration of the book life of the investment (assumed to be 30 years for initial permitting costs and 10 years for the various compliance technologies) or the years remaining in the modeling horizon, whichever is shorter.[8]

- ***Fixed O&M cost*** inputs into the IPM are expressed in terms of dollars per KW of capacity per year.

- ***Variable O&M cost*** inputs are expressed in dollars per megawatt hour (MWh) of generation.

[7] Of the 543 surveyed facilities subject to the section 316(b) Phase II rule, eight are not modeled in the IPM. Three facilities are in Hawaii and one is in Alaska. Neither state is represented in the IPM. Four facilities are on-site generators that do not provide electricity to the grid.

[8] The capital charge rate is a function of capital structure (debt/equity shares of an investment), pre-tax debt rate (or interest cost), debt life, post-tax return on equity, corporate income tax, depreciation schedule, book life of the investment, and other costs including property tax and insurance. The discount rate is a function of capital structure, pre-tax debt rate, and post-tax return on equity.

- ***Permitting costs*** consist of initial permitting costs, annual monitoring costs, repermitting costs (occurring every five years after issuance of the initial permit), and, for some facilities, pilot study costs. Permitting cost inputs are expressed as follows: initial permitting and pilot study activities are necessary for the on-going operation of the plant and are therefore added to the capital costs for technologies with a 30-year useful life; annual monitoring and annualized repermitting costs are added to the fixed O&M costs.

- ***Capacity reductions*** consist of a one-time generator downtime. Generator downtime estimates reflect the amount of time generators are off-line while compliance technologies are constructed and/or installed and are expressed in weeks. The generator downtime is a one-time event that affects several of the compliance technologies evaluated by EPA. Generator downtime is estimated to occur during the year when a facility complies with the policy option. Since the years that are mapped into a run year are assumed to have the same characteristics as the run year itself, generator downtimes were applied as an average over the years that are mapped into each model run year.[9] Estimated generator downtimes due to construction and/or installation range from two to eleven weeks (see also Chapter B1, Table B1-1).

The IPM operates at the boiler level. It was therefore necessary to distribute facility-level costs across affected boilers. EPA used the following methodology:

- Steam electric generators operating at each of the 535 modeled section 316(b) facilities were identified using data from the IPM.

- Generator-specific design intake flows were obtained from Form EIA-767 (1998).[10]

- Facility-level compliance costs were distributed across each facility's steam generators. For facilities with available design intake flow data, this distribution was based on each generator's proportion of total design intake volume; for facilities without available design intake flow, this distribution was based on each generator's proportion of total steam electric capacity.

- Generator-level compliance costs were aggregated to the boiler level based on the EPA's Base Case 2000 cross-walk between boilers and generators.

B3-2.4 Model Outputs

The IPM generates a series of outputs on different levels of aggregation (boiler, model plant, region, and nation). The economic analysis for the Phase II rule used a subset of the available IPM output. For each model run (base case and each analyzed policy option) and for each model run year (2008, 2010, 2013, and 2020) the following model outputs were generated:

- ***Capacity*** – Capacity is a measure of the ability to generate electricity. This output measure reflects the summer net dependable capacity of all generating units at the plant. The model differentiates between existing capacity, new capacity additions, and existing capacity that has been repowered.[11]

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[9] For example, a facility with a downtime in 2008 was modeled as if 1/5th of its downtime occurred in each year between 2005 and 2009. A potential drawback of this approach of averaging downtimes over the mapped years is that the snapshot of the effect of downtimes during the model run year is the average effect; this approach does not model potential worst case effects of above-average amounts of capacity being down in any one NERC region during any one year.

[10] This information is provided in Schedule IV - Generator Information, Question 3.A (Design flow rate for the condenser at 100% load). Design intake flow data at the generator level is not available for nonutilities nor for those utility owned plants with a steam generating capacity less than 100 MW. Generator-level design intake flow data were not available for 57 of the 535 modeled facilities.

[11] Repowering in the IPM consists of converting oil/gas or coal capacity to combined-cycle capacity. The modeling assumption is that each one MW of existing capacity is replaced by two MW of repowered capacity.

- ***Early Retirements*** – The IPM models two types of plant closures: closures of nuclear plants as a result of license expiration and economic closures as a result of negative net present value of future operation.[12] This analysis only considers economic closures in assessing the impacts of the final rule and other regulatory alternatives. However, cases where a nuclear facility decides to renew its license in the base case but does not renew its license in the post-compliance case for a given policy option are also considered economic closures and an impact of that policy option.

- ***Energy Price*** – The average annual price received for the sale of electricity.

- ***Capacity Price*** – The premium over energy prices received by facilities operating in peak hours during which system load approaches available capacity. The capacity price is the premium required to stimulate new market entrants to construct additional capacity, cover costs, and earn a return on their investment. This price manifests as short term price spikes during peak hours and, in long-run equilibrium, need be only so large as is required to justify investment in new capacity.

- ***Generation*** – The amount of electricity produced by each plant that is available for dispatch to the transmission grid ("net generation").

- ***Energy Revenue*** – Revenues from the sale of electricity to the grid.

- ***Capacity Revenue*** – Revenues received by facilities operating in hours where the price of energy exceeds the variable production cost of generation for the next unit to be dispatched at that price in order to maintain reliable energy supply in the short run. At these peak hours, the price of energy includes a premium which reflects the cost of the required reserve margin and serves to stimulate investment in the additional capacity required to maintain a long run equilibrium in the supply and demand for capacity.

- ***Fuel Costs*** – The cost of fuel consumed in the generation of electricity.

- ***Variable Operation and Maintenance Costs*** – Non-fuel O&M costs that vary with the level of generation, e.g., cost of consumables, including water, lubricants, and electricity.

- ***Fixed Operation and Maintenance Costs*** – O&M costs that do not vary with the level of generation, e.g., labor costs and capital expenditures for maintenance. In post-compliance scenarios, fixed O&M costs also include annualized capital costs of compliance and permitting costs.

- ***Capital Costs*** – The cost of construction, equipment, and capital. Capital costs are associated with investment in new equipment, e.g., the replacement of a boiler or condenser, installation of technologies to meet the requirements of air regulations, or the repowering of a plant.

B3-3 Economic Impact Analysis Methodology

The outputs presented in the previous section were used to identify changes to economic and operational characteristics such as capacity, generation, revenue, cost of generation, and electricity prices associated with Phase II regulatory options. EPA developed impact measures at two analytic levels: (1) the market as a whole, including all facilities and (2) the subset of in-scope Phase II facilities. Both analyses were conducted by NERC region. In both cases, the impacts of each option are defined as the difference between the model output for the base case scenario (i.e., the model run in the absence of section 316(b) Phase II regulations) and the post-compliance scenario. The following subsections describe the impact measures used for the two levels of analysis.

[12] Nuclear plants are evaluated for economic viability at the end of their license term. Nuclear units that, at age 30, did not make a major maintenance investment, are provided with a 10-year life extension, if they are economically viable. These same units may subsequently undertake a 20-year re-licensing option at age 40. Nuclear units that already had made a maintenance investment are provided with a 20-year re-licensing option at age 40, if they are economically viable. All nuclear units are ultimately retired at age 60.

B3-3.1 Market-level Impact Measures

The market-level analysis evaluates regional changes as a result of Phase II regulatory options. Seven main measures are analyzed:

- ***(1) Changes in available capacity:*** This measure analyzes changes in the capacity available to generate electricity. A long-term reduction in availability may be the result of partial or full closures of plants subject to the rule. In the short term, temporary plant shut-downs for the installation of Phase II compliance technologies may lead to reductions in available capacity.[13] When analyzing changes in available capacity, EPA distinguished between **existing capacity**, **new capacity additions**, and **repowering additions**. Under this measure, EPA also analyzed capacity **closures**. Only capacity that is projected to remain operational in the base case but is closed in the post-compliance case is considered a closure as the result of the rule. An option may result in partial (i.e., unit) or full plant closures. An option may also result in avoided closures if a facility's compliance costs are low relative to other affected facilities. An avoided closure is a unit or plant that would close in the base case but operates in the post-compliance case.

- ***(2) Changes in the price of electricity:*** This measure considers changes in regional prices as a result of Phase II regulation. In the long term, electricity prices may change as a result of increased production costs of the Phase II facilities. In the short-term, price increases may be higher if large power plants have to temporarily shut down to construct and/or install Phase II compliance technologies. This analysis considers changes in both **energy prices** and **capacity prices**.

- ***(3) Changes in generation:*** This measure considers the amount of electricity generated. At a regional level, long-term changes in generation may be the result of plant closures or a change in the amount of electricity traded between regions. In the short term, temporary plant shut-downs to install Phase II compliance technologies may lead to reductions in generation. At the national level, the demand for electricity does not change between the base case and the analyzed policy options (generation within the regions is allowed to vary). However, demand for electricity does vary across the modeling horizon according to the model's underlying electricity demand growth assumptions.

- ***(4) Changes in revenues:*** This measure considers the revenues realized by all facilities in the market and includes both energy revenues and capacity revenues (see definition in section B3-2.4 above). A change in revenues could be the result of a change in generation and/or the price of electricity.

- ***(5) Changes in costs:*** This measure considers changes in the overall cost of generating electricity, including fuel costs, variable and fixed O&M costs, and capital costs. **Fuel costs** and **variable O&M costs** are production costs that vary with the level of generation. Fuel costs generally account for the single largest share of production costs. **Fixed O&M costs** and **capital costs** do not vary with generation. They are fixed in the short-term and therefore do not affect the dispatch decision of a unit (given sufficient demand, a unit will dispatch as long as the price of electricity is at least equal to its per MWh production costs). However, in the long-run, these costs need to be recovered for a unit to remain economically viable.

- ***(6) Changes in pre-tax income:*** Pre-tax income is defined as total revenues minus total costs and is an indicator of profitability. Pre-tax income may decrease as a result of reductions in revenues and/or increases in costs.

- ***(7) Changes in variable production costs per MWh:*** This measure considers the regional change in average variable production cost per MWh. Variable production costs include fuel costs and other variable O&M costs but exclude fixed O&M costs and capital costs. Production cost per MWh is a primary determinant of how often a power plant's units are dispatched. This measure presents similar information to total fuel and variable O&M costs under measure (5) above, but normalized for changes in generation.

[13] Such short-term capacity reductions would not be expressed as changes in available capacity but might affect electricity generation, production costs, and/or prices.

B3-3.2 Facility-level Impact Measures (In-scope Facilities Only)

EPA used the IPM results to analyze impacts on in-scope Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the in-scope Phase II facilities as a group and (2) potential changes to individual facilities within the group of in-scope Phase II facilities.

a. In-scope Phase II facilities as a group

The analysis of the in-scope Phase II facilities as a group is largely similar to the market-level analysis described in Section B3-3.1 above, except that the base case and policy option totals only include the economic activities of the 535 in-scope Phase II facilities represented by the model. In addition, a few measures differ: (1) new capacity additions and prices are not relevant at the facility level, (2) the number of Phase II facilities that experience closure of all their steam electric capacity is presented, and (3) repowering changes are not explicitly analyzed at the facility level. Following are the measures evaluated for the group of Phase II facilities:

- ***(1) Changes in available capacity:*** This measure considers the capacity available at the 535 Phase II facilities. A long-term reduction in availability may be the result of partial or full plant closures, a change in the decision to repower, or a change in the choice of air pollution control technologies. In the short term, temporary plant shut-downs for the installation of Phase II compliance technologies may lead to reductions in available capacity.[14] Under this measure, EPA also analyzed **closures**. Only capacity that is projected to remain operational in the base case but is closed in the post-compliance case is considered a closure as the result of the rule. An option may result in partial (i.e., unit) or full plant closures. An option may also result in avoided closures if a facility's compliance costs are low relative to other affected facilities. An avoided closure is a unit or plant that would close in the base case but operates in the post-compliance case. At the facility-level, both the number of full closure facilities and closure capacity are analyzed.

- ***(2) Changes in generation:*** This measure considers the generation at the 535 Phase II facilities. Long-term changes in generation may be the result of a reduction in available capacity (see discussion above) or the less frequent dispatch of a plant due to higher production cost as a result of the policy option. In the short term, temporary plant shut-downs may lead to reductions in generation at some of the 535 Phase II facilities. For some Phase II facilities, Phase II regulation may lead to an increase in generation if their compliance costs are low relative to other affected facilities.

- ***(3) Changes in revenues:*** This measure considers the revenues realized by the 535 Phase II facilities and includes both energy revenues and capacity revenues (see definition in section B3-2.4 above). A change in revenues could be the result of a change in generation and/or the price of electricity. For some modeled 316(b) facilities, Phase II regulation may lead to an increase in revenues if their generation increases as a result of the rule, or if the rule leads to an increase in electricity prices.

- ***(4) Changes in costs:*** This measure considers changes in the overall cost of generating electricity for the 535 Phase II facilities, including fuel costs, variable and fixed O&M costs, and capital costs. **Fuel costs** and **variable O&M costs** are production costs that vary with the level of generation. Fuel costs generally account for the single largest share of production costs. **Fixed O&M costs** and **capital costs** do not vary with generation. They are fixed in the short-term and therefore do not affect the dispatch decision of a unit (given sufficient demand, a unit will dispatch as long as the price of electricity is at least equal to its per MWh production costs). However, in the long-run, these costs need to be recovered for a unit to remain economically viable.

- ***(5) Changes in pre-tax income:*** Pre-tax income is defined as total revenues minus total costs and is an indicator of profitability. Pre-tax income may decrease as a result of reductions in revenues and/or increases in costs.

- ***(6) Changes in variable production costs per MWh:*** This measure considers the plant-level change in the average annual variable production cost per MWh. Variable production costs include fuel costs and other variable O&M costs but exclude fixed O&M costs and capital costs.

[14] Such short-term capacity reductions would not be expressed as changes in available capacity but might affect electricity generation, production costs, and/or prices.

b. Individual Phase II facilities

To assess potential distributional impacts among individual Phase II facilities, EPA analyzed facility-specific changes to a number of key measures. For each measure, EPA determined the number of Phase II facilities that experience an increase or a reduction, respectively, within three ranges: 1 percent or less, 1 to 3 percent, and more than 3 percent. EPA conducted this analysis for the following measures:

- ***(1) Changes in capacity utilization:*** Capacity utilization is defined as a unit's actual generation divided by its potential generation, if it ran 100 percent of the time (i.e., generation / (capacity * 365 days * 24 hours)). This measure indicates how frequently a unit is dispatched and earns energy revenues for its owner.
- ***(2) Changes in generation:*** See explanation in subsection a. above.
- ***(3) Changes in revenues:*** See explanation in subsection a. above.
- ***(4) Changes in variable production costs per MWh:*** See explanation in subsection a. above.
- ***(5) Changes in fuel costs per MWh:*** See explanation in subsection a. above.
- ***(6) Changes in pre-tax income:*** See explanation in subsection a. above.

B3-4 Analysis Results for the Final Rule

The remainder of this section presents the results of the economic impact analysis of the final Phase II rule for the ten NERC regions modeled by the IPM. The analysis is based on IPM output for the base case (using EPA electricity demand assumptions) and the final rule. Results are presented at the market level and the Phase II facility level.

The main analysis in this chapter uses output from model run year 2010. For this analysis, facilities subject to the final rule are assumed to come into compliance during the year of their first post-promulgation national pollution discharge elimination system (NPDES) permit (2005 to 2009). Therefore, 2010 is assumed to be the first year during which all facilities are in compliance, but no facilities experience technology installation downtimes. 2010 thus represents the post-compliance condition of the industry. EPA also analyzed potential market-level impacts of the final rule for a year within the compliance period during which some Phase II facilities experience installation downtimes. This secondary analysis represents potential short-term impacts of the final rule and uses output from model run year 2008.

B3-4.1 Market Analysis for 2010

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The market-level analysis includes results for all generators located in each NERC region including facilities that are in-scope and facilities that are out-of-scope of Phase II regulation.

Table B3-4 presents the market-level impact measures discussed in section B3-3.1 above: (1) capacity changes, including changes in existing capacity, new additions, repowering additions, and closures; (2) electricity price changes, including changes in energy prices and capacity prices; (3) generation changes; (4) revenue changes; (5) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (6) changes in pre-tax income; and (7) changes in variable production costs per MWh of generation. For each measure, the table presents the results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference.

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
National Totals				
(1) Total Domestic Capacity (MW)	887,915	887,863	(52)	0.0%
(1a) Existing	787,280	786,922	(359)	0.0%
(1b) New Additions	79,683	79,540	(143)	(0.2)%
(1c) Repowering Additions	20,951	21,402	451	2.2%
(1d) Closures	14,122	14,274	152	1.1%
(2a) Energy Prices ($2002/MWh)	n/a	n/a	n/a	n/a
(2b) Capacity Prices ($2002/KW/yr)	n/a	n/a	n/a	n/a
(3) Generation (GWh)	4,113,839	4,113,668	(170)	0.0%
(4) Revenues (Millions; $2002)	$138,770	$138,676	($94)	(0.1)%
(5) Costs (Millions; $2002)	$87,486	$87,915	$429	0.5%
(5a) Fuel Cost	$47,789	$47,782	($7)	0.0%
(5b) Variable O&M	$7,926	$7,927	$1	0.0%
(5c) Fixed O&M	$23,417	$23,827	$410	1.8%
(5d) Capital Cost	$8,354	$8,378	$24	0.3%
(6) Pre-Tax Income (Millions; $2002)	$51,284	$50,761	($523)	(1.0)%
(7) Variable Production Costs ($/MWh)	$13.54	$13.54	$0.00	0.0%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	118,529	118,529	0	0.0%
(1a) Existing	110,066	110,066	0	0.0%
(1b) New Additions	8,394	8,394	0	0.0%
(1c) Repowering Additions	70	70	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$22.63	$22.69	$0.06	0.3%
(2b) Capacity Prices ($2002/KW/yr)	$56.08	$56.15	$0.07	0.1%
(3) Generation (GWh)	649,024	647,671	(1,354)	(0.2)%
(4) Revenues (Millions; $2002)	$21,317	$21,334	$17	0.1%
(5) Costs (Millions; $2002)	$12,492	$12,576	$84	0.7%
(5a) Fuel Cost	$6,367	$6,358	($9)	(0.1)%
(5b) Variable O&M	$1,585	$1,583	($2)	(0.1)%
(5c) Fixed O&M	$3,570	$3,668	$98	2.7%
(5d) Capital Cost	$970	$968	($3)	(0.3)%
(6) Pre-Tax Income (Millions; $2002)	$8,825	$8,758	($67)	(0.8)%
(7) Variable Production Costs ($/MWh)	$12.25	$12.26	$0.01	0.1%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	75,290	75,290	0	0.0%
(1a) Existing	71,901	71,721	(180)	(0.2)%
(1b) New Additions	2,053	1,871	(182)	(8.8)%
(1c) Repowering Additions	1,336	1,697	361	27.0%
(1d) Closures	0	0	0	0.0%

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
(2a) Energy Prices ($2002/MWh)	$29.38	$31.08	$1.69	5.8%
(2b) Capacity Prices ($2002/KW/yr)	$14.09	$4.83	($9.26)	(65.7)%
(3) Generation (GWh)	336,956	336,663	(293)	(0.1)%
(4) Revenues (Millions; $2002)	$10,961	$10,826	($135)	(1.2)%
(5) Costs (Millions; $2002)	$8,000	$8,031	$31	0.4%
(5a) Fuel Cost	$5,241	$5,234	($7)	(0.1)%
(5b) Variable O&M	$699	$700	$1	0.2%
(5c) Fixed O&M	$1,730	$1,754	$24	1.4%
(5d) Capital Cost	$330	$343	$13	4.1%
(6) Pre-Tax Income (Millions; $2002)	$2,961	$2,795	($166)	(5.6)%
(7) Variable Production Costs ($/MWh)	$17.63	$17.62	$0.00	0.0%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	50,324	50,324	0	0.0%
(1a) Existing	39,262	39,267	5	0.0%
(1b) New Additions	11,062	11,057	(5)	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	812	812	0	0.0%
(2a) Energy Prices ($2002/MWh)	$29.39	$29.55	$0.16	0.6%
(2b) Capacity Prices ($2002/KW/yr)	$37.79	$36.82	($0.98)	(2.6)%
(3) Generation (GWh)	189,076	188,844	(232)	(0.1)%
(4) Revenues (Millions; $2002)	$7,459	$7,434	($25)	(0.3)%
(5) Costs (Millions; $2002)	$5,406	$5,442	$36	0.7%
(5a) Fuel Cost	$3,106	$3,113	$7	0.2%
(5b) Variable O&M	$364	$365	$2	0.4%
(5c) Fixed O&M	$1,184	$1,217	$33	2.8%
(5d) Capital Cost	$753	$747	($6)	(0.8)%
(6) Pre-Tax Income (Millions; $2002)	$2,053	$1,992	($61)	(3.0)%
(7) Variable Production Costs ($/MWh)	$18.35	$18.42	$0.07	0.4%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	63,784	63,784	0	0.0%
(1a) Existing	56,355	56,355	0	0.0%
(1b) New Additions	5,771	5,771	0	0.0%
(1c) Repowering Additions	1,658	1,658	0	0.0%
(1d) Closures	2,831	2,831	0	0.0%
(2a) Energy Prices ($2002/MWh)	$26.73	$26.76	$0.02	0.1%
(2b) Capacity Prices ($2002/KW/yr)	$50.61	$50.44	($0.17)	(0.3)%
(3) Generation (GWh)	276,051	277,764	1,714	0.6%
(4) Revenues (Millions; $2002)	$10,605	$10,646	$41	0.4%
(5) Costs (Millions; $2002)	$6,124	$6,206	$82	1.3%
(5a) Fuel Cost	$3,066	$3,101	$34	1.1%

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	EPA Base Case	Final Rule	Difference	% Change
(5b) Variable O&M	$557	$560	$3	0.5%
(5c) Fixed O&M	$1,929	$1,969	$39	2.0%
(5d) Capital Cost	$571	$577	$5	0.9%
(6) Pre-Tax Income (Millions; $2002)	$4,481	$4,440	($41)	(0.9)%
(7) Variable Production Costs ($/MWh)	$13.13	$13.18	$0.05	0.4%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	59,494	59,397	(97)	(0.2)%
(1a) Existing	51,551	51,465	(86)	(0.2)%
(1b) New Additions	7,943	7,932	(11)	(0.1)%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	5,191	5,285	94	1.8%
(2a) Energy Prices ($2002/MWh)	$22.66	$22.60	($0.06)	(0.3)%
(2b) Capacity Prices ($2002/KW/yr)	$54.31	$54.66	$0.35	0.7%
(3) Generation (GWh)	281,625	281,446	(179)	(0.1)%
(4) Revenues (Millions; $2002)	$9,607	$9,602	($5)	(0.1)%
(5) Costs (Millions; $2002)	$5,795	$5,802	$7	0.1%
(5a) Fuel Cost	$2,930	$2,933	$3	0.1%
(5b) Variable O&M	$586	$583	($3)	(0.5)%
(5c) Fixed O&M	$1,710	$1,726	$15	0.9%
(5d) Capital Cost	$569	$560	($9)	(1.6)%
(6) Pre-Tax Income (Millions; $2002)	$3,812	$3,800	($11)	(0.3)%
(7) Variable Production Costs ($/MWh)	$12.48	$12.49	$0.01	0.1%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	35,835	35,835	0	0.0%
(1a) Existing	32,672	32,676	4	0.0%
(1b) New Additions	3,163	3,159	(4)	(0.1)%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	476	476	0	0.0%
(2a) Energy Prices ($2002/MWh)	$21.86	$21.79	($0.06)	(0.3)%
(2b) Capacity Prices ($2002/KW/yr)	$54.00	$54.49	$0.49	0.9%
(3) Generation (GWh)	181,713	181,566	(147)	(0.1)%
(4) Revenues (Millions; $2002)	$5,878	$5,881	$3	0.0%
(5) Costs (Millions; $2002)	$3,430	$3,431	$1	0.0%
(5a) Fuel Cost	$1,722	$1,719	($3)	(0.2)%
(5b) Variable O&M	$381	$379	($2)	(0.5)%
(5c) Fixed O&M	$1,017	$1,029	$12	1.2%
(5d) Capital Cost	$311	$304	($7)	(2.2)%
(6) Pre-Tax Income (Millions; $2002)	$2,448	$2,450	$2	0.1%
(7) Variable Production Costs ($/MWh)	$11.57	$11.56	($0.02)	(0.1)%

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	EPA Base Case	Final Rule	Difference	% Change
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	72,477	72,459	(19)	0.0%
(1a) Existing	59,515	59,513	(2)	0.0%
(1b) New Additions	2,082	2,061	(21)	(1.0)%
(1c) Repowering Additions	10,881	10,885	4	0.0%
(1d) Closures	4,107	4,107	0	0.0%
(2a) Energy Prices ($2002/MWh)	$29.88	$29.85	($0.02)	(0.1)%
(2b) Capacity Prices ($2002/KW/yr)	$43.23	$43.22	($0.01)	0.0%
(3) Generation (GWh)	278,649	277,433	(1,216)	(0.4)%
(4) Revenues (Millions; $2002)	$11,220	$11,173	($46)	(0.4)%
(5) Costs (Millions; $2002)	$7,732	$7,751	$18	0.2%
(5a) Fuel Cost	$4,479	$4,438	($41)	(0.9)%
(5b) Variable O&M	$376	$372	($4)	(1.0)%
(5c) Fixed O&M	$1,781	$1,846	$65	3.6%
(5d) Capital Cost	$1,096	$1,095	($2)	(0.1)%
(6) Pre-Tax Income (Millions; $2002)	$3,488	$3,423	($65)	(1.9)%
(7) Variable Production Costs ($/MWh)	$17.42	$17.34	($0.08)	(0.5)%
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	194,485	194,472	(13)	0.0%
(1a) Existing	164,544	164,544	0	0.0%
(1b) New Additions	29,941	29,928	(13)	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$24.64	$24.62	($0.02)	(0.1)%
(2b) Capacity Prices ($2002/KW/yr)	$48.23	$48.40	$0.17	0.4%
(3) Generation (Gwh)	944,631	945,913	1,283	0.1%
(4) Revenues (Millions; $2002)	$32,644	$32,690	$46	0.1%
(5) Costs (Millions; $2002)	$19,753	$19,865	$112	0.6%
(5a) Fuel Cost	$10,314	$10,323	$8	0.1%
(5b) Variable O&M	$1,785	$1,790	$5	0.3%
(5c) Fixed O&M	$5,264	$5,343	$79	1.5%
(5d) Capital Cost	$2,389	$2,408	$20	0.8%
(6) Pre-Tax Income (Millions; $2002)	$12,891	$12,826	($66)	(0.5)%
(7) Variable Production Costs ($/MWh)	$12.81	$12.81	$0.00	0.0%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	49,948	50,092	144	0.3%
(1a) Existing	48,956	48,900	(56)	(0.1)%
(1b) New Additions	992	1,080	88	8.9%
(1c) Repowering Additions	0	111	111	100.0%

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	EPA Base Case	Final Rule	Difference	% Change
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$24.34	$24.29	($0.05)	(0.2)%
(2b) Capacity Prices ($2002/KW/yr)	$40.97	$41.24	$0.27	0.7%
(3) Generation (GWh)	221,527	221,854	327	0.1%
(4) Revenues (Millions; $2002)	$7,434	$7,450	$16	0.2%
(5) Costs (Millions; $2002)	$4,254	$4,282	$28	0.7%
(5a) Fuel Cost	$2,701	$2,702	$1	0.0%
(5b) Variable O&M	$422	$422	($1)	(0.1)%
(5c) Fixed O&M	$1,042	$1,057	$14	1.4%
(5d) Capital Cost	$88	$101	$13	14.7%
(6) Pre-Tax Income (Millions; $2002)	$3,181	$3,168	($12)	(0.4)%
(7) Variable Production Costs ($/MWh)	$14.10	$14.08	($0.02)	(0.1)%
Western Systems Coordinating Council (WSCC)				
(1) Total Domestic Capacity (MW)	167,748	167,681	(67)	0.0%
(1a) Existing	152,459	152,414	(45)	0.0%
(1b) New Additions	8,283	8,287	4	0.0%
(1c) Repowering Additions	7,006	6,980	(26)	(0.4)%
(1d) Closures	705	763	58	8.2%
(2a) Energy Prices ($2002/MWh)	$27.19	$27.18	($0.01)	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$7.56	$7.58	$0.03	0.3%
(3) Generation (GWh)	754,587	754,514	(73)	0.0%
(4) Revenues (Millions; $2002)	$21,645	$21,639	($6)	0.0%
(5) Costs (Millions; $2002)	$14,499	$14,530	$30	0.2%
(5a) Fuel Cost	$7,863	$7,862	($1)	0.0%
(5b) Variable O&M	$1,171	$1,173	$1	0.1%
(5c) Fixed O&M	$4,189	$4,220	$31	0.7%
(5d) Capital Cost	$1,277	$1,275	($2)	(0.1)%
(6) Pre-Tax Income (Millions; $2002)	$7,146	$7,110	($36)	(0.5)%
(7) Variable Production Costs ($/MWh)	$11.97	$11.97	$0.00	0.0%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA electricity demand assumptions).

Summary of Market Results at the National Level. The results presented in Table B3-4 show that capacity closures are estimated to increase by 152 MW, which represents 0.02 percent of total baseline capacity. New additions are estimated to decrease by 143 MW. An increase in repowering additions (451 MW) is estimated to make up for this loss. Total costs of electricity generation will increase by 0.5 percent, largely because of a 1.8 percent increase in fixed O&M costs (which includes charges for capital costs of compliance). Revenues are estimated to decrease by 0.1 percent and pre-tax income is estimated to decrease by 1.0 percent. The final rule will not lead to changes in total domestic capacity or total fuel costs.

Summary of Market Results at the Regional Level. At the regional level, the final rule is estimated to result in the following changes:

- **MAIN** and **WSCC** are the only regions that are estimated to experience an increase in post-compliance capacity closures. In MAIN, the 94 MW increase in closures (0.2 percent of baseline capacity) is due to a nuclear facility that reached the end of its nuclear operating license. In the base case, this facility would have extended its license for 481 MW of capacity and continued operation until 2020. Under the final rule, however, this facility is modeled to only extend its license for 387 MW of capacity. As a result, MAIN also experiences a decrease in capital costs. In WSCC, oil and gas early retirements account for the 58 MW increase in closures (less than 0.1 percent of baseline capacity). All other measures are estimated to change by less than 1.0 percent.

- **ERCOT** is estimated to experience the most notable changes in electricity prices and new capacity among the ten NERC regions. Repowering additions will increase by 361 MW (0.5 percent of baseline capacity) under the final rule. Repowering in the IPM is modeled as a conversion of one MW of existing coal or oil and gas steam capacity into two MW of combined-cycle capacity. As such, repowering in ERCOT under the final rule consists of the conversion of 180 MW of existing capacity into 361 MW of new repowered capacity. Since total capacity in ERCOT remains constant, this 181 MW net increase in capacity is offset by a 182 MW decrease in new capacity additions. Repowering of oil and gas to combined cycle will cause capital costs to increase by 4.1 percent. Post-compliance energy prices are estimated to increase by 5.8 percent. This increase is largely driven by relatively low profit margins in the region. ERCOT also experiences the largest reduction in capacity prices with almost 66 percent. This is partially due to the increase in energy prices, which allows facilities to bid their undispatched capacity at a lower price. Revenues and pre-tax income in ERCOT are estimated to fall by 1.2 percent and 5.6 percent, respectively, the highest in any NERC region.

- **FRCC** is estimated to experience a 2.6 percent reduction in capacity prices. Revenues in FRCC are estimated to decrease by 0.3 percent and costs will increase by 0.7 percent (largely due to an increase in fixed O&M costs of 2.8 percent), leading to a reduction in pre-tax income of 3.0 percent the second highest in any NERC region. All other measures are estimated to change by less than 1.0 percent.

- **NPCC** is estimated to have the largest percentage reduction in generation of the ten NERC regions (0.4 percent). As a result variable O&M costs decreases by 1.0 percent. Fixed O&M costs, which include the capital costs of compliance with the final rule, increase by 3.6 percent, and pre-tax income decreases by 1.9 percent, the third highest in any NERC region. Revenues and overall costs in NPCC are estimated to each change by less than 0.5 percent.

- **ECAR**, **MAPP,** and **SERC**, are estimated to experience increases in fixed O&M costs, driven by the capital costs of compliance with the final rule, but overall cost increases in each region will be less than 1.0 percent. Pre-tax income in these regions is estimated to decrease by between 0.5 and 0.8 percent, with the exception of MAPP which is estimated to experience a slight increase in pre-tax income. MAPP will also experience a decrease in capital costs (2.2 percent) due to the avoided cost of retrofitting a scrubber. All other measures are estimated to change by less than 1.0 percent.

- **SPP** is the only region estimated to experience an increase in total capacity. This increase is the result of 88 MW in incremental new additions and 111 MW in repowering additions. However, these changes represent less than 0.5 percent of overall capacity. Similar to ECAR, MAPP, and SERC, SPP will experience increases in fixed O&M costs. SPP is estimated to have the largest increase in capital costs of the ten NERC regions (14.7 percent). The majority of additional capital costs comes from the repowering additions. Pretax income is estimated to decrease by 0.4 percent.

- **MAAC** is estimated to experience the largest increase in generation (0.6 percent) and fuel cost (1.1 percent) as a result of the final rule. Fixed O&M costs are estimated to rise by 2.0 percent, leading to an increase in total costs of 1.3 percent. Together with FRCC, MAAC also has the largest increase in variable production cost per MWh of generation, 0.4 percent. All other measures are estimated to change by less than 1.0 percent.

B3-4.2 Analysis of Phase II Facilities for 2010

This section presents the results of the IPM analysis for the Phase II facilities that are modeled by the IPM. Ten of the 535 Phase II facilities are closures in the base case, and 11 facilities are closures under the final rule. These facilities are not represented in the results described in this section.

EPA used the IPM results from model run year 2010 to analyze impacts on Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the in-scope Phase II facilities as a group and (2) potential changes to individual facilities within the group of in-scope Phase II facilities.

a. In-scope Phase II facilities as a group

This section presents the analysis of the potential impacts of the final rule on the in-scope Phase II facilities as a group. This analysis is similar to the market-level analysis described above but is limited to facilities subject to the requirements of the section 316(b) rule. Table B3-5 presents the impact measures for the group of Phase II facilities discussed in section B3-3.2 above: (1) capacity changes, including changes in the number and capacity of closure facilities; (2) generation changes; (3) revenue changes; (4) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (5) changes in pre-tax income; and (6) changes in variable production costs per MWh of generation, where variable production cost is defined as the sum of fuel cost and variable O&M cost. For each measure, the table presents the results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference.

Table B3-5: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	EPA Base Case	Final Rule	Difference	% Change
National Totals				
(1) Total Domestic Capacity (MW)	433,998	433,062	(936)	(0.2)%
(1a) Closures - Number of Facilities	10	11	1	10.0%
(1b) Closures - Capacity (MW)	13,644	13,796	152	1.1%
(2) Generation (GWh)	2,323,322	2,304,461	(18,861)	(0.8)%
(3) Revenues (Millions; $2002)	$76,259	$75,585	($673)	(0.9)%
(4) Costs (Millions; $2002)	$48,264	$48,092	($173)	(0.4)%
(4a) Fuel Cost	$25,391	$24,990	($400)	(1.6)%
(4b) Variable O&M	$5,154	$5,130	($24)	(0.5)%
(4c) Fixed O&M	$15,159	$15,552	$393	2.6%
(4d) Capital Cost	$2,561	$2,420	($142)	(5.5)%
(5) Pre-Tax Income (Millions; $2002)	$27,994	$27,494	($501)	(1.8)%
(6) Variable Production Costs ($2002/MWh)	$13.15	$13.07	($0.08)	(0.6)%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	82,313	82,313	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	1	1	0	0.0%
(2) Generation (GWh)	517,126	516,220	(906)	(0.2)%
(3) Revenues (Millions; $2002)	$16,237	$16,250	$13	0.1%
(4) Costs (Millions; $2002)	$9,586	$9,668	$82	0.9%
(4a) Fuel Cost	$5,036	$5,022	($14)	(0.3)%
(4b) Variable O&M	$1,248	$1,248	$0	0.0%
(4c) Fixed O&M	$2,961	$3,059	$98	3.3%
(4d) Capital Cost	$342	$340	($2)	(0.7)%
(5) Pre-Tax Income (Millions; $2002)	$6,651	$6,582	($69)	(1.0)%
(6) Variable Production Costs ($2002/MWh)	$12.15	$12.15	($0.01)	0.0%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	43,522	43,413	(109)	(0.3)%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0
(2) Generation (GWh)	158,462	155,661	(2,800)	(1.8)%

Table B3-5: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
(3) Revenues (Millions; $2002)	$5,365	$5,158	($206)	(3.8)%
(4) Costs (Millions; $2002)	$3,910	$3,855	($55)	(1.4)%
(4a) Fuel Cost	$2,203	$2,142	($61)	(2.8)%
(4b) Variable O&M	$426	$422	($4)	(0.9)%
(4c) Fixed O&M	$1,181	$1,204	$23	1.9%
(4d) Capital Cost	$99	$86	($13)	(12.9)%
(5) Pre-Tax Income (Millions; $2002)	$1,455	$1,303	($152)	(10.4)%
(6) Variable Production Costs ($2002/MWh)	$16.59	$16.48	($0.12)	(0.7)%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	27,537	27,542	5	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	812	812	0	0.0%
(2) Generation (GWh)	82,259	81,631	(628)	(0.8)%
(3) Revenues (Millions; $2002)	$3,433	$3,398	($35)	(1.0)%
(4) Costs (Millions; $2002)	$2,021	$2,042	$21	1.0%
(4a) Fuel Cost	$1,154	$1,148	($6)	(0.5)%
(4b) Variable O&M	$188	$187	$0	(0.2)%
(4c) Fixed O&M	$673	$706	$33	4.9%
(4d) Capital Cost	$5	$0	($5)	(100.0)%
(5) Pre-Tax Income (Millions; $2002)	$1,412	$1,356	($56)	(4.0)%
(6) Variable Production Costs ($2002/MWh)	$16.31	$16.36	$0.05	0.3%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	34,376	34,376	0	0.0%
(1a) Closures - Number of Facilities	2	2	0	0.0%
(1b) Closures - Capacity (MW)	2,831	2,831	0	0.0%
(2) Generation (GWh)	173,473	173,782	309	0.2%
(3) Revenues (Millions; $2002)	$6,339	$6,343	$4	0.1%
(4) Costs (Millions; $2002)	$3,617	$3,658	$42	1.2%
(4a) Fuel Cost	$1,693	$1,696	$3	0.2%
(4b) Variable O&M	$355	$356	$1	0.3%
(4c) Fixed O&M	$1,438	$1,476	$38	2.6%
(4d) Capital Cost	$131	$131	$0	0.0%
(5) Pre-Tax Income (Millions; $2002)	$2,722	$2,685	($37)	(1.4)%
(6) Variable Production Costs ($2002/MWh)	$11.81	$11.81	$0.00	0.0%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	36,498	36,412	(86)	(0.2)%
(1a) Closures - Number of Facilities	2	2	0	0.0%
(1b) Closures - Capacity (MW)	5,191	5,285	94	1.8%
(2) Generation (GWh)	226,437	225,826	(610)	(0.3)%

Table B3-5: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
(3) Revenues (Millions; $2002)	$7,011	$6,993	($17)	(0.2)%
(4) Costs (Millions; $2002)	$4,196	$4,196	$0	0.0%
(4a) Fuel Cost	$2,109	$2,108	($1)	(0.1)%
(4b) Variable O&M	$510	$506	($3)	(0.7)%
(4c) Fixed O&M	$1,472	$1,486	$14	1.0%
(4d) Capital Cost	$106	$96	($9)	(8.9)%
(5) Pre-Tax Income (Millions; $2002)	$2,815	$2,797	($18)	(0.6)%
(6) Variable Production Costs ($2002/MWh)	$11.56	$11.58	$0.01	0.1%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	15,749	15,753	4	0.0%
(1a) Closures - Number of Facilities	1	1	0	0.0%
(1b) Closures - Capacity (MW)	476	476	0	0.0%
(2) Generation (GWh)	108,584	108,533	(52)	0.0%
(3) Revenues (Millions; $2002)	$3,178	$3,179	$1	0.0%
(4) Costs (Millions; $2002)	$1,978	$1,982	$4	0.2%
(4a) Fuel Cost	$1,044	$1,044	$0	0.0%
(4b) Variable O&M	$222	$221	($2)	(0.7)%
(4c) Fixed O&M	$597	$609	$12	2.0%
(4d) Capital Cost	$114	$107	($6)	(5.7)%
(5) Pre-Tax Income (Millions; $2002)	$1,200	$1,197	($3)	(0.3)%
(6) Variable Production Costs ($2002/MWh)	$11.67	$11.65	($0.01)	(0.1)%
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	37,651	37,343	(308)	(0.8)%
(1a) Closures - Number of Facilities	4	4	0	0.0%
(1b) Closures - Capacity (MW)	4,107	4,107	0	0.0%
(2) Generation (GWh)	165,601	159,701	(5,900)	(3.6)%
(3) Revenues (Millions; $2002)	$6,503	$6,300	($203)	(3.1)%
(4) Costs (Millions; $2002)	$5,114	$4,971	($143)	(2.8)%
(4a) Fuel Cost	$2,756	$2,607	($149)	(5.4)%
(4b) Variable O&M	$276	$266	($9)	(3.4)%
(4c) Fixed O&M	$1,242	$1,305	$62	5.0%
(4d) Capital Cost	$840	$793	($47)	(5.6)%
(5) Pre-Tax Income (Millions; $2002)	$1,389	$1,329	($60)	(4.3)%
(6) Variable Production Costs ($2002/MWh)	$18.31	$17.99	($0.32)	(1.7)%
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	107,450	107,450	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	639,276	637,804	(1,472)	(0.2)%
(3) Revenues (Millions; $2002)	$20,645	$20,617	($28)	(0.1)%

Table B3-5: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	EPA Base Case	Final Rule	Difference	% Change
(4) Costs (Millions; $2002)	$12,038	$12,071	$34	0.3%
(4a) Fuel Cost	$6,137	$6,097	($39)	(0.6)%
(4b) Variable O&M	$1,365	$1,366	$2	0.1%
(4c) Fixed O&M	$3,986	$4,058	$72	1.8%
(4d) Capital Cost	$550	$549	($1)	(0.2)%
(5) Pre-Tax Income (Millions; $2002)	$8,607	$8,546	($62)	(0.7)%
(6) Variable Production Costs ($2002/MWh)	$11.73	$11.70	($0.03)	(0.3)%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	20,471	20,471	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	109,901	109,185	(716)	(0.7)%
(3) Revenues (Millions; $2002)	$3,419	$3,401	($18)	(0.5)%
(4) Costs (Millions; $2002)	$1,962	$1,958	($3)	(0.2)%
(4a) Fuel Cost	$1,148	$1,135	($13)	(1.2)%
(4b) Variable O&M	$248	$247	($2)	(0.6)%
(4c) Fixed O&M	$557	$569	$13	2.3%
(4d) Capital Cost	$8	$7	($1)	(13.9)%
(5) Pre-Tax Income (Millions; $2002)	$1,457	$1,443	($14)	(1.0)%
(6) Variable Production Costs ($2002/MWh)	$12.71	$12.65	($0.05)	(0.4)%
Western Systems Coordinating Council (WSCC)				
(1) Total Domestic Capacity (MW)	28,431	27,989	(443)	-1.6%
(1a) Closures - Number of Facilities	1	2	1	100.0%
(1b) Closures - Capacity (MW)	226	284	58	25.7%
(2) Generation (GWh)	142,204	136,117	(6,086)	-4.3%
(3) Revenues (Millions; $2002)	$4,131	$3,947	($183)	-4.4%
(4) Costs (Millions; $2002)	$3,844	$3,691	($153)	-4.0%
(4a) Fuel Cost	$2,109	$1,990	($119)	-5.6%
(4b) Variable O&M	$317	$311	($6)	-1.9%
(4c) Fixed O&M	$1,051	$1,079	$28	2.6%
(4d) Capital Cost	$367	$310	($56)	-15.4%
(5) Pre-Tax Income (Millions; $2002)	$287	$257	($30)	-10.4%
(6) Variable Production Costs ($2002/MWh)	$17.06	$16.90	($0.15)	-0.9%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA electricity demand assumptions).

Comparison of Results for Phase II Facilities and the Market. The IPM results for the in-scope Phase II facilities as a group (presented in Table B3-5) are similar to the results at the market level (presented in Table B3-4). On a percentage basis, the group of Phase II facilities generally experiences higher losses in generation, revenues, and pre-tax income compared to the overall market. This is not surprising as in-scope facilities become relatively less competitive compared to facilities not in scope of Phase II regulation and are therefore likely to lose some market share as a result of the final rule.

Total closure capacity among the Phase II facilities is the same as at the market level but represents a higher percentage of total base case capacity. Fixed O&M costs of the group of Phase II facilities increase relatively more than at the market level because fixed O&M costs include the capital costs of compliance with Phase II regulatory options. In many regions, however, the other cost accounts decrease for the Phase II facilities because of the reduction in generation. On a per MWh basis, variable production costs also decrease in many regions because the higher cost units generate less electricity under the final rule compared to the base case, reducing the overall average cost of generation.

Summary of Phase II Facility Results at the National Level. Table B3-5 shows that the final rule will lead to 152 MW in incremental capacity closures, or less than 0.5 percent of baseline Phase II capacity. These incremental closures are estimated to be one full facility closure of 19 MW in WSCC and partial facility closures of 39 MW in WSCC and 94 MW in MAIN. Total Phase II capacity is projected to decrease by 936 MW, due to the capacity closures and several facilities that were projected to repower in the base case but do not under the final rule. As a result, generation, revenues, and overall costs will decrease but by less than one percent. Fixed O&M costs, which include the capital cost of compliance, are projected to increase by 2.6 percent. Pre-tax income for the group of Phase II facilities will decrease by 1.8 percent.

Summary of Phase II Facility Results at the Regional Level. Results for the final rule vary somewhat by region. For many regions, impacts follow the general pattern described in the comparison to the market level above: generation, revenues, and pre-tax income decrease. Overall costs decrease in many regions due to lower levels of generation but increase in other regions where the additional compliance costs outweigh the reduction in generation. In addition to these general patterns, EPA estimates that the final rule will result in the following changes:

- **WSCC** is estimated to experience the largest reduction in Phase II capacity, losing 443 MW, or 1.6 percent of base case capacity under the final rule. This change is partially the result of a full facility closure of 19 MW and a partial facility closure of 39 MW. However, the majority of the 443 MW reduction is the result of less Phase II capacity being repowered in the post-compliance scenario. Phase II facilities in WSCC also experience the largest reductions in generation and revenues of any NERC region (4.3 and 4.4 percent, respectively) because they bear a relatively high compliance cost per MW of capacity under the final rule (the second highest of any of the 10 NERC regions). In addition, only a small percentage of total capacity in WSCC (28,400 MW out of 167,750 MW, or 17 percent) is subject to Phase II regulation. As a result, facilities not subject to Phase II regulation become relatively more competitive and assume some of the generation lost by Phase II facilities. Overall, costs for the group of Phase II facilities decrease by 4.0 percent. Fixed O&M costs, which include Phase II compliance costs, increase but fuel costs and variable O&M costs decrease because of the reduction in generation. However, the reduction in revenues outweighs the reduction in costs, leading to an overall reduction in pre-tax income of 10.4 percent ($30 million), which is the highest, together with ERCOT, in any NERC region. This relatively high percentage reduction is partially due to the low profit margins of Phase II facilities in WSCC in the base case.

- **MAIN** is the only other region, besides WSCC, that is projected to experience an incremental closure of Phase II capacity under the final rule, losing 94 MW of capacity (0.3% of base case capacity). The reduction is due to a nuclear facility that reached the end of its nuclear operating license. In the base case the facility would have extended its license for 481 MW of capacity, and continued operating until 2020. Under the final rule the facility only extends its license for 387 MW of capacity. The incremental capacity closure is responsible for the reduction in Phase II capacity in the region and contributes to a decrease in Phase II post-compliance generation and revenues. Total costs remain the same, but variable production cost per MWh increase because the projected incremental closure affects nuclear capacity which has lower production costs than most other plant types.

- Phase II facilities in **ERCOT** are estimated to experience the highest reductions pre-tax income (-10.4 percent), together with facilities in WSCC. In addition, generation (-1.8 percent) and revenues (-3.8 percent) are predicted to decrease. Revenues decrease by a larger percentage than generation due to the large drop in capacity prices (see Table B3-4). Capital costs decrease by 12.9 percent (the largest reduction other than FRCC). A majority of the reduction is the result of one less facility repowering under the final rule.

- Phase II facilities in **NPCC** are estimated to experience the largest increase in fixed O&M costs of any NERC region (5.0 percent) as a result of bearing the highest compliance cost per MW of capacity under the final rule. NPCC facilities will also experience the second largest reduction in generation (-3.6 percent) and the third largest reduction in pre-tax income (-4.3 percent) of any region.

- Phase II facilities in **FRCC** are estimated to experience an increase in total costs of 1.0 percent under the final rule, which is driven by a 4.9 percent increase in fixed O&M costs. Combined with a reduction in revenues of 1.0 percent, this will reduce pre-tax income for Phase II facilities in FRCC by 4.0 percent.

- **ECAR**, **MAAC**, **MAPP**, and **SERC**, and **SPP** are estimated to experience relatively small reductions in pre-tax income (between 0.3 and 1.4 percent) as a result of increases in fixed O&M costs (between 1.8 to 3.3 percent). The changes in most other measures are less than 1.0 percent in these regions.

b. Individual Phase II facilities

In addition to effects of the final rule on the in-scope Phase II facilities as a group, there may be shifts in economic performance among individual facilities subject to Phase II regulation. To assess such potential shifts, EPA analyzed facility-specific changes in (1) capacity utilization (defined as generation divided by capacity multiplied by the number of hours per year – 8,760); (2) generation; (3) revenues; (4) variable production costs per MWh of generation (defined as variable O&M cost plus fuel cost divided by generation); (5) fuel cost per MWh of generation; and (6) pre-tax income. For each measure, EPA determined the number of Phase II facilities that experience no changes, or an increase or a reduction within three ranges: 1 percent or less, 1 to 3 percent, and more than 3 percent.

Table B3-6 presents the total number of Phase II facilities with different estimated degrees of change due to the final rule. This table excludes 17 in-scope facilities with estimated significant status changes in 2010: Ten facilities are baseline closures, one facility is a full closure as a result of the final rule, and six facilities changed their repowering decision between the base case and the post-compliance case. These facilities are either not operating at all in either the base case or the post-compliance case, or they experience fundamental changes in the type of units they operate; therefore, the measures presented in Table B3-6 would not be meaningful for these facilities. In addition, the change in variable production cost per MWh and fuel cost per MWh of generation could not be developed for 57 facilities with zero generation in either the base case or post-compliance scenario. For these facilities, the change in variable production cost per MWh is indicated as "n/a."

Table B3-6: Number of Individual Phase II Facilities with Operational Changes (2010)

Economic Measures	Reduction			Increase			No Change	N/A
	</= 1%	1-3%	> 3%	</= 1%	1-3%	> 3%		
(1) Change in Capacity Utilization	6	21	25	7	7	11	441	0
(2) Change in Generation	4	6	46	11	5	18	428	0
(3) Change in Revenues	83	30	45	142	8	16	194	0
(4) Change in Variable Production Costs/MWh	38	16	9	145	11	17	225	57
(5) Change in Fuel Costs/MWh	27	14	10	38	8	13	351	57
(6) Change in Pre-Tax Income	115	109	213	44	11	15	11	0

[a] For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.
[b] The change in capacity utilization is the difference between the capacity utilization percentages in the base case and post-compliance case. For all other measures, the change is expressed as the percentage change between the base case and post-compliance values.

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA electricity demand assumptions).

Table B3-6 indicates that the majority of Phase II facilities will not experience changes in capacity utilization, generation, or fuel costs per MWh due to compliance with the final rule. Of those facilities with changes in post-compliance capacity utilization and generation, most will experience decreases in these measures. The majority of facilities with changes in post-compliance variable production costs per MWh will experience increases. However, more than 80 percent of those increases will not exceed 1.0 percent. Changes in revenues at most Phase II facilities will also not exceed 1.0 percent. The largest effect of the final rule will be on facilities' pre-tax income: over 80 percent of facilities will experience a reduction in pre-tax income, with about 40 percent experiencing a reduction of 3.0 percent or greater. These reductions are due to a combination of reduced revenues and increased compliance costs.

B3-4.3 Market Analysis for 2008

This section presents market-level results for the final rule for model run year 2008. Unlike the market-level analysis for 2010 described above, model run year 2008 includes facilities that experience a one-time downtime due to the installation of Phase II compliance technologies. This analysis therefore presents potential short-term effects that may occur during the five-year period (2005 to 2009) represented by model run year 2008. However, it should be noted that not all facilities are in compliance by 2008. Therefore, potential effects of installation downtimes may be mitigated by the fact that some facilities will not incur compliance costs until after 2008.

Table B3-7 presents the following market-level impacts for 2008: (1) electricity price changes, including changes in energy prices and capacity prices; (2) generation changes; (3) revenue changes; (4) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (5) changes in pre-tax income; and (6) changes in variable production costs per MWh. For each measure, the table presents the 2008 results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference. The table also repeats the percentage difference based on the market-level analysis for 2010 presented in Table B3-4 above.

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)

Economic Measures	EPA Base Case	Final Rule	Difference	% Change	% Change 2010
National Totals					
(1a) Energy Price ($2002/MWh)	n/a	n/a	n/a	n/a	n/a
(1b) Capacity Price ($2002/KW)	n/a	n/a	n/a	n/a	n/a
(2) Total Generation (GWh)	4,060,238	4,060,401	163	0.0%	0.0%
(3) Total Revenues (Millions; $2002)	$154,018	$153,946	($72)	0.0%	(0.1)%
(4) Costs (Millions; $2002)	$86,389	$86,909	$520	0.6%	0.5%
(4a) Fuel Cost	$48,097	$48,182	$85	0.2%	0.0%
(4b) Variable O&M	$7,828	$7,825	($4)	0.0%	0.0%
(4c) Fixed O&M	$23,643	$24,012	$369	1.6%	1.8%
(4d) Capital Cost	$6,821	$6,890	$69	1.0%	0.3%
(5) Pre-Tax Income (Millions; $2002)	$67,629	$67,037	($592)	(0.9)%	(1.0)%
(6) Variable Production Costs ($2002/MWh)	$13.77	$13.79	$0.02	0.1%	0.0%
East Central Area Reliability Coordination Agreement (ECAR)					
(1a) Energy Price ($2002/MWh)	$22.66	$23.01	$0.35	1.5%	0.3%
(1b) Capacity Price ($2002/KW)	$78.35	$78.01	($0.34)	(0.4)%	0.1%
(2) Total Generation (GWh)	649,365	646,400	(2,965)	(0.5)%	(0.2)%
(3) Total Revenues (Millions; $2002)	$23,972	$24,091	$119	0.5%	0.1%
(4) Costs (Millions; $2002)	$12,731	$12,771	$41	0.3%	0.7%
(4a) Fuel Cost	$6,619	$6,576	($43)	(0.6)%	(0.1)%
(4b) Variable O&M	$1,579	$1,574	($5)	(0.3)%	(0.1)%
(4c) Fixed O&M	$3,569	$3,661	$91	2.6%	2.7%
(4d) Capital Cost	$964	$961	($3)	(0.3)%	(0.3)%
(5) Pre-Tax Income (Millions; $2002)	$11,241	$11,320	$78	0.7%	(0.8)%
(6) Variable Production Costs ($2002/MWh)	$12.62	$12.61	($0.02)	(0.1)%	0.1%

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)					
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**	**% Change 2010**
Electric Reliability Council of Texas (ERCOT)					
(1a) Energy Price ($2002/MWh)	$29.98	$30.12	$0.14	0.5%	5.8%
(1b) Capacity Price ($2002/KW)	$0.00	$0.00	$0.00	0.0%	(65.7)%
(2) Total Generation (GWh)	325,835	325,835	0	0.0%	(0.1)%
(3) Total Revenues (Millions; $2002)	$9,768	$9,813	$45	0.5%	(1.2)%
(4) Costs (Millions; $2002)	$7,728	$7,766	$38	0.5%	0.4%
(4a) Fuel Cost	$5,211	$5,205	($6)	(0.1)%	(0.1)%
(4b) Variable O&M	$673	$672	($1)	(0.2)%	0.2%
(4c) Fixed O&M	$1,696	$1,714	$18	1.1%	1.4%
(4d) Capital Cost	$148	$175	$27	18.5%	4.1%
(5) Pre-Tax Income (Millions; $2002)	$2,040	$2,048	$7	0.4%	(5.6)%
(6) Variable Production Costs ($2002/MWh)	$18.06	$18.04	($0.02)	(0.1)%	0.0%
Florida Reliability Coordinating Council (FRCC)					
(1a) Energy Price ($2002/MWh)	$30.18	$30.38	$0.20	0.7%	0.6%
(1b) Capacity Price ($2002/KW)	$63.07	$62.64	($0.43)	(0.7)%	(2.6)%
(2) Total Generation (GWh)	186,234	186,200	(34)	0.0%	(0.1)%
(3) Total Revenues (Millions; $2002)	$8,719	$8,734	$15	0.2%	(0.3)%
(4) Costs (Millions; $2002)	$5,349	$5,386	$37	0.7%	0.7%
(4a) Fuel Cost	$3,129	$3,150	$22	0.7%	0.2%
(4b) Variable O&M	$354	$355	$1	0.3%	0.4%
(4c) Fixed O&M	$1,172	$1,193	$20	1.7%	2.8%
(4d) Capital Cost	$694	$688	($6)	(0.8)%	(0.8)%
(5) Pre-Tax Income (Millions; $2002)	$3,370	$3,348	($22)	(0.7)%	(3.0)%
(6) Variable Production Costs ($2002/MWh)	$18.70	$18.83	$0.13	0.7%	0.4%
Mid-Atlantic Area Council (MAAC)					
(1a) Energy Price ($2002/MWh)	$26.82	$27.12	$0.30	1.1%	0.1%
(1b) Capacity Price ($2002/KW)	$73.68	$73.85	$0.17	0.2%	(0.3)%
(2) Total Generation (GWh)	274,753	275,349	596	0.2%	0.6%
(3) Total Revenues (Millions; $2002)	$12,024	$12,133	$108	0.9%	0.4%
(4) Costs (Millions; $2002)	$5,985	$6,047	$62	1.0%	1.3%
(4a) Fuel Cost	$2,920	$2,941	$20	0.7%	1.1%
(4b) Variable O&M	$553	$554	$1	0.2%	0.5%
(4c) Fixed O&M	$2,125	$2,160	$35	1.6%	2.0%
(4d) Capital Cost	$386	$392	$6	1.6%	0.9%
(5) Pre-Tax Income (Millions; $2002)	$6,039	$6,086	$46	0.8%	(0.9)%

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)					
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**	**% Change 2010**
(6) Variable Production Costs ($2002/MWh)	$12.64	$12.69	$0.05	0.4%	0.4%
Mid-America Interconnected Network (MAIN)					
(1a) Energy Price ($2002/MWh)	$22.68	$22.96	$0.28	1.2%	(0.3)%
(1b) Capacity Price ($2002/KW)	$78.80	$77.97	($0.82)	(1.0)%	0.7%
(2) Total Generation (GWh)	285,282	286,219	937	0.3%	(0.1)%
(3) Total Revenues (Millions; $2002)	$11,208	$11,221	$13	0.1%	(0.1)%
(4) Costs (Millions; $2002)	$5,940	$5,963	$23	0.4%	0.1%
(4a) Fuel Cost	$2,940	$2,960	$20	0.7%	0.1%
(4b) Variable O&M	$589	$593	$3	0.6%	(0.5)%
(4c) Fixed O&M	$1,949	$1,972	$23	1.2%	0.9%
(4d) Capital Cost	$463	$439	($24)	(5.2)%	(1.6)%
(5) Pre-Tax Income (Millions; $2002)	$5,268	$5,258	($10)	(0.2)%	(0.3)%
(6) Variable Production Costs ($2002/MWh)	$12.37	$12.41	$0.04	0.3%	0.1%
Mid-Continent Area Power Pool (MAPP)					
(1a) Energy Price ($2002/MWh)	$22.41	$22.72	$0.32	1.4%	(0.3)%
(1b) Capacity Price ($2002/KW)	$78.32	$78.02	($0.30)	(0.4)%	0.9%
(2) Total Generation (GWh)	179,067	178,742	(325)	(0.2)%	(0.1)%
(3) Total Revenues (Millions; $2002)	$6,756	$6,794	$38	0.6%	0.0%
(4) Costs (Millions; $2002)	$3,353	$3,362	$9	0.3%	0.0%
(4a) Fuel Cost	$1,740	$1,737	($2)	(0.1)%	(0.2)%
(4b) Variable O&M	$366	$365	$0	(0.1)%	(0.5)%
(4c) Fixed O&M	$998	$1,012	$14	1.4%	1.2%
(4d) Capital Cost	$249	$247	($1)	(0.5)%	(2.2)%
(5) Pre-Tax Income (Millions; $2002)	$3,404	$3,432	$28	0.8%	0.1%
(6) Variable Production Costs ($2002/MWh)	$11.76	$11.76	$0.00	0.0%	(0.1)%
Northeast Power Coordinating Council (NPCC)					
(1a) Energy Price ($2002/MWh)	$29.48	$30.35	$0.87	3.0%	(0.1)%
(1b) Capacity Price ($2002/KW)	$68.95	$58.24	($10.71)	(15.5)%	0.0%
(2) Total Generation (GWh)	277,871	277,129	(743)	(0.3)%	(0.4)%
(3) Total Revenues (Millions; $2002)	$12,806	$12,309	($496)	(3.9)%	(0.4)%
(4) Costs (Millions; $2002)	$7,668	$7,710	$43	0.6%	0.2%
(4a) Fuel Cost	$4,459	$4,447	($13)	(0.3)%	(0.9)%
(4b) Variable O&M	$376	$372	($3)	(0.9)%	(1.0)%
(4c) Fixed O&M	$1,779	$1,837	$58	3.3%	3.6%
(4d) Capital Cost	$1,053	$1,054	$0	0.0%	(0.1)%
(5) Pre-Tax Income (Millions; $2002)	$5,138	$4,599	($539)	(10.5)%	(1.9)%

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)

Economic Measures	EPA Base Case	Final Rule	Difference	% Change	% Change 2010
(6) Variable Production Costs ($2002/MWh)	$17.40	$17.39	($0.01)	(0.1)%	(0.5)%
Southeastern Electric Reliability Council (SERC)					
(1a) Energy Price ($2002/MWh)	$25.48	$25.57	$0.10	0.4%	(0.1)%
(1b) Capacity Price ($2002/KW)	$68.91	$68.51	($0.40)	(0.6)%	0.4%
(2) Total Generation (GWh)	924,991	927,191	2,199	0.2%	0.1%
(3) Total Revenues (Millions; $2002)	$36,464	$36,577	$113	0.3%	0.1%
(4) Costs (Millions; $2002)	$19,134	$19,316	$183	1.0%	0.6%
(4a) Fuel Cost	$10,337	$10,376	$39	0.4%	0.1%
(4b) Variable O&M	$1,760	$1,759	$0	0.0%	0.3%
(4c) Fixed O&M	$5,182	$5,253	$70	1.4%	1.5%
(4d) Capital Cost	$1,854	$1,928	$74	4.0%	0.8%
(5) Pre-Tax Income (Millions; $2002)	$17,330	$17,261	($69)	(0.4)%	(0.5)%
(6) Variable Production Costs ($2002/MWh)	$13.08	$13.09	$0.01	0.1%	0.0%
Southwest Power Pool (SPP)					
(1a) Energy Price ($2002/MWh)	$25.17	$25.31	$0.14	0.5%	(0.2)%
(1b) Capacity Price ($2002/KW)	$61.73	$61.15	($0.57)	(0.9)%	0.7%
(2) Total Generation (GWh)	217,634	217,539	(95)	0.0%	0.1%
(3) Total Revenues (Millions; $2002)	$8,503	$8,499	($5)	(0.1)%	0.2%
(4) Costs (Millions; $2002)	$4,214	$4,224	$10	0.2%	0.7%
(4a) Fuel Cost	$2,743	$2,746	$3	0.1%	0.0%
(4b) Variable O&M	$419	$419	$0	0.1%	(0.1)%
(4c) Fixed O&M	$1,031	$1,041	$10	1.0%	1.4%
(4d) Capital Cost	$21	$18	($4)	(17.6)%	14.7%
(5) Pre-Tax Income (Millions; $2002)	$4,289	$4,275	($15)	(0.3)%	(0.4)%
(6) Variable Production Costs ($2002/MWh)	$14.53	$14.55	$0.02	0.1%	(0.1)%
Western Systems Coordinating Council (WSCC)					
(1a) Energy Price ($2002/MWh)	$28.58	$28.71	$0.13	0.5%	0.0%
(1b) Capacity Price ($2002/KW)	$18.17	$17.25	($0.92)	(5.0)%	0.3%
(2) Total Generation (GWh)	739,205	739,797	592	0.1%	0.0%
(3) Total Revenues (Millions; $2002)	$23,797	$23,774	($22)	(0.1)%	0.0%
(4) Costs (Millions; $2002)	$14,287	$14,362	$75	0.5%	0.2%
(4a) Fuel Cost	$7,999	$8,044	$45	0.6%	0.0%
(4b) Variable O&M	$1,160	$1,161	$1	0.1%	0.1%
(4c) Fixed O&M	$4,140	$4,169	$29	0.7%	0.7%
(4d) Capital Cost	$989	$988	($1)	(0.1)%	(0.1)%

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)					
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**	**% Change 2010**
(5) Pre-Tax Income (Millions; $2002)	$9,509	$9,412	($97)	(1.0)%	(0.5)%
(6) Variable Production Costs ($2002/MWh)	$12.39	$12.44	$0.05	0.4%	0.0%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA electricity demand assumptions).

Summary of Market Results at the National Level. The results presented in Table B3-7 show that under the final rule downtimes associated with the installation of compliance technologies will not lead to significant changes in economic impacts compared to the results for 2010 (which represents the post-compliance scenario in which no facilities experience downtimes). There will be an 0.2 percent increase in fuel costs in 2008, leading to an increase in variable production cost per MWh of 0.1 percent. In addition, the rise in capital costs is estimated to be somewhat higher in 2008 than in 2010.

Summary of Market Results at the Regional Level. The following discussion highlights differences in the analysis results between 2010 and 2008:

- In **FRCC** and **SERC**, most impact results for 2008 and 2010 are either the same or slightly lower in 2008. **FRCC** is estimated to experience a smaller decrease in capacity prices in 2008 which will result in higher revenues and a smaller loss in pre-tax income compared to 2010. In **SERC**, energy prices and generation are estimated to increase more in 2008 than 2010, leading to an increase in revenues and a reduction in pre-tax income loss.

- **ECAR**, **MACC**, and **MAPP** are estimated to experience increases in energy prices between 1.1 and 1.5 percent in 2008. These increases will lead to higher revenues and increases in pre-tax income of between 0.7 and 0.8 percent.

- **NPCC**, and **WSCC** are both estimated to experience increases in energy prices under the final rule in 2008. However, capacity prices are estimated to decrease, leading to a reduction in revenues and pre-tax income. In **WSCC**, fuel costs will increase by 0.6 percent, resulting in an 0.4 percent increase in variable production costs per Mwh.

- **MAIN** is estimated to experience increases in energy prices and a decrease in capacity prices under the final rule in 2008, similar to **NPCC** and **WSCC**. However, generation is estimated to increase rather than decrease in 2008 as compared to 2010, resulting in higher revenues and a smaller decrease in pre-tax income.

- **ERCOT** is estimated to experience substantially lower price effects in 2008 compared to 2010. The increase in energy prices will be 0.5 percent compared to 5.8 percent in 2010. Capacity prices in 2008 are zero in both the base case and under the final rule as a result of excess capacity in the region (note that there are no new capacity additions in ERCOT in 2008). ERCOT is also estimated to experience an increase in revenues and an increase in pre-tax income compared to 2010.

- In **SPP**, energy prices under the final rule are estimated to increase by 0.5 percent in 2008 while capacity prices will fall, resulting in a 0.1 percent reduction in revenues. The only other notable difference in results compared to 2010 is a relatively large percentage reduction in capital costs in 2008. This is the result of a minor delay in investment in new capacity additions under the final rule: approximately 120 MW of capacity that is projected to be built in 2008 in the base case is postponed until 2010 under the final rule. As a result, 2008 sees a reduction in capital costs while 2010 sees an increase. Overall, the reduction in capital costs in 2008 comprises less than 0.1 percent of total base case cost.

B3-5 UNCERTAINTIES AND LIMITATIONS

There are uncertainties associated with EPA's analysis of the electric power market and the economic impacts of the final rule:

- ***Demand for electricity:*** The IPM assumes that electricity demand at the national level would not change between the base case and the analyzed policy options (generation within the regions is allowed to vary). Under the EPA Base Case 2000 specification, electricity demand is based on the AEO 2001 forecast adjusted to account for demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The IPM model, as specified for this analysis, does not capture changes in demand that may result from electricity price increases associated with the final rule. While this constraint may overestimate total demand in policy options that have high compliance cost and that may therefore lead to significant price increases, EPA believes that it does not affect the results analyzed in support of the final rule. As described in Section B3-4 above, the price increases associated with the final rule in most NERC regions are relatively small. EPA therefore concludes that the assumption of inelastic demand-responses to changes in prices is reasonable.

- ***International imports:*** The IPM also assumes that imports from Canada and Mexico would not change between the base case and the analyzed policy options. Holding international imports fixed would provide a conservative estimate of production costs and electricity prices, because imports are not subject to the rule and may therefore become more competitive relative to domestic capacity, displacing some of the more expensive domestic generating units. On the other hand, holding imports fixed may understate effects on marginal domestic units, which may be displaced by increased imports. However, EPA concludes that fixed imports do not materially affect the results of the analyses. In 2010 only four of the ten NERC regions import electricity (ECAR, MAPP, NPCC, and WSCC) and the level of imports compared to domestic generation in each of these regions is very small (0.03 percent in ECAR, 2.4 percent in MAPP, 6 percent in NPCC, and 1.5 percent in WSCC).

- ***Repowering:*** For the section 316(b) analysis, EPA is not using the IPM function that allows the model to pick among a set of compliance responses. As a result, there is no iterative process that would adjust the compliance response (and as a result the cost of compliance) if a facility chooses to repower. Repowering in the IPM typically consists of the conversion of existing oil/gas or coal capacity to new combined-cycle capacity. The modeling assumption is that each one MW of existing capacity is replaced by two MW of repowered capacity. This change in plant type and size might lead to a change in intake flow and potentially to different compliance requirements and costs. Since combined-cycle facilities require substantially less cooling water than other oil/gas or coal facilities, the effect of repowering is likely to be a reduction in cooling water requirements (even considering the doubling of the plant's capacity). As a result, not allowing the model to adjust the compliance response or cost is likely to lead to a conservative estimate of compliance costs and potential economic impacts from the final rule.

- ***Downtime associated with installation of compliance technologies:*** EPA estimates that the installation of several compliance technologies would require the steam electric generators of facilities that are projected to install such technologies to be off-line. Downtime is estimated to range between two and eleven weeks, depending on the technology. Generator downtime is estimated to occur during the year when a facility complies with the final rule. Since the years that are mapped into a run year are assumed to have the same characteristics as the run year itself, generator downtimes were applied as an average over the years that are mapped into each model run year. For example, years 2005 to 2009 are all mapped into 2008. Therefore, a facility with a downtime in 2008 was modeled as if 1/5th of its downtime occurred in each year between 2005 and 2009. A potential drawback of this approach of averaging downtimes over the mapped years is that the snapshot of the effect of downtimes during the model run year is the average effect; this approach does not model potential worst case effects of above-average amounts of capacity being down in any one NERC region during any one year.

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Chapter B3 - Appendix A

INTRODUCTION

CHAPTER CONTENTS

This appendix presents additional electricity market model results for the final Phase II rule, using alternative assumptions about future growth in electricity demand. In the analyses presented in the body of this chapter, electricity demand was based on the Annual Energy Outlook 2001 (AEO2001) forecast adjusted to account for demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The analyses presented in this appendix are based on the unadjusted AEO2001 forecasts.

B3-A.1 ALTERNATIVE ANALYSIS RESULTS

The following subsections present results for (1) the entire market (i.e., all generators including facilities that are in-scope and facilities that are out-of-scope of Phase II regulation); (2) the in-scope Phase II facilities as a group; and (3) individual Phase II facilities. The tables are equivalent to the tables for the final rule presented in the section B3-4, except for the change in electricity demand assumptions. In addition, Tables B3-A-2 and B3-A-4 present a comparison of the changes as a result of the final rule under the two different electricity demand assumptions.

B3-A.1-1 Market Analysis for 2010 – AEO Assumptions

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The market-level analysis includes results for all generators located in each North American Electric Reliability Council (NERC) region including facilities that are in-scope and facilities that are out-of-scope of Phase II regulation.

Table B3-A-1 below (equivalent to Table B3-4) presents seven measures of market-level impacts associated with the final rule: (1) capacity changes, including changes in existing capacity, new additions, repowering additions, and closures; (2) electricity price changes, including changes in energy prices and capacity prices; (3) generation changes; (4) revenue changes; (5) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (6) changes in pre-tax income, defined as revenues minus total costs; and (7) changes in variable production costs per MWh. For each measure, the Table presents the results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference by NERC region. A detailed description of each of the impact measures is presented in Section B3-3.1 of this chapter.

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	AEO Base Case	Final Rule	Difference	% Change
National Totals				
(1) Total Domestic Capacity (MW)	947,406	947,434	28	0.0%
(1a) Existing	788,986	788,046	(940)	(0.1)%
(1b) New Additions	133,162	133,214	52	0.0%
(1c) Repowering Additions	25,258	26,174	916	3.6%
(1d) Closures	10,203	10,696	493	4.8%
(2a) Energy Prices ($2002/MWh)	n/a	n/a	n/a	n/a
(2b) Capacity Prices ($2002/KW/yr)	n/a	n/a	n/a	n/a
(3) Generation (GWh)	4,400,321	4,400,761	440	0.0%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	AEO Base Case	Final Rule	Difference	% Change
(4) Revenues (Millions; $2002)	$156,989	$156,991	$2	0.0%
(5) Costs (Millions; $2002)	$98,824	$99,243	$419	0.4%
(5a) Fuel Cost	$53,473	$53,471	($3)	0.0%
(5b) Variable O&M	$8,320	$8,325	$5	0.1%
(5c) Fixed O&M	$24,484	$24,862	$377	1.5%
(5d) Capital Cost	$12,547	$12,586	$39	0.3%
(6) Pre-Tax Income (Millions; $2002)	$58,165	$57,748	($417)	(0.7)%
(7) Variable Production Costs ($/MWh)	$14.04	$14.04	$0.00	0.0%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	127,332	127,098	(233)	(0.2)%
(1a) Existing	110,034	110,044	10	0.0%
(1b) New Additions	17,228	16,984	(244)	(1.4)%
(1c) Repowering Additions	70	70	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$24.82	$24.82	$0.01	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$54.17	$54.18	$0.00	0.0%
(3) Generation (GWh)	680,905	681,417	511	0.1%
(4) Revenues (Millions; $2002)	$23,781	$23,786	$5	0.0%
(5) Costs (Millions; $2002)	$13,854	$13,939	$85	0.6%
(5a) Fuel Cost	$6,963	$6,984	$21	0.3%
(5b) Variable O&M	$1,659	$1,658	($1)	(0.1)%
(5c) Fixed O&M	$3,658	$3,751	$93	2.5%
(5d) Capital Cost	$1,573	$1,546	($28)	(1.8)%
(6) Pre-Tax Income (Millions; $2002)	$9,927	$9,847	($80)	(0.8)%
(7) Variable Production Costs ($/MWh)	$12.66	$12.68	$0.02	0.2%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	80,472	80,473	1	0.0%
(1a) Existing	69,845	69,398	(448)	(0.6)%
(1b) New Additions	5,202	4,756	(446)	(8.6)%
(1c) Repowering Additions	5,425	6,319	895	16.5%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$27.20	$27.55	$0.35	1.3%
(2b) Capacity Prices ($2002/KW/yr)	$34.13	$32.33	($1.81)	(5.3)%
(3) Generation (GWh)	362,415	362,415	0	0.0%
(4) Revenues (Millions; $2002)	$12,605	$12,581	($24)	(0.2)%
(5) Costs (Millions; $2002)	$9,054	$9,089	$36	0.4%
(5a) Fuel Cost	$5,760	$5,755	($5)	(0.1)%
(5b) Variable O&M	$719	$718	($1)	(0.2)%
(5c) Fixed O&M	$1,783	$1,805	$22	1.2%
(5d) Capital Cost	$791	$811	$20	2.5%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(6) Pre-Tax Income (Millions; $2002)	$3,551	$3,492	($59)	(1.7)%
(7) Variable Production Costs ($/MWh)	$17.88	$17.86	($0.02)	(0.1)%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	53,831	53,832	0	0.0%
(1a) Existing	39,238	39,239	2	0.0%
(1b) New Additions	14,594	14,592	(2)	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	812	812	0	0.0%
(2a) Energy Prices ($2002/MWh)	$30.19	$30.34	$0.16	0.5%
(2b) Capacity Prices ($2002/KW/yr)	$37.42	$36.49	($0.94)	(2.5)%
(3) Generation (GWh)	204,711	204,697	(13)	0.0%
(4) Revenues (Millions; $2002)	$8,194	$8,175	($19)	(0.2)%
(5) Costs (Millions; $2002)	$6,104	$6,146	$42	0.7%
(5a) Fuel Cost	$3,472	$3,477	$4	0.1%
(5b) Variable O&M	$393	$396	$3	0.8%
(5c) Fixed O&M	$1,237	$1,272	$35	2.8%
(5d) Capital Cost	$1,001	$1,000	($1)	(0.1)%
(6) Pre-Tax Income (Millions; $2002)	$2,090	$2,030	($61)	(2.9)%
(7) Variable Production Costs ($/MWh)	$18.88	$18.92	$0.04	0.2%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	68,838	68,782	(56)	(0.1)%
(1a) Existing	57,461	57,461	0	0.0%
(1b) New Additions	9,719	9,662	(56)	(0.6)%
(1c) Repowering Additions	1,658	1,658	0	0.0%
(1d) Closures	1,725	1,725	0	0.0%
(2a) Energy Prices ($2002/MWh)	$27.99	$28.01	$0.02	0.1%
(2b) Capacity Prices ($2002/KW/yr)	$51.00	$50.90	($0.10)	(0.2)%
(3) Generation (GWh)	299,588	299,044	(543)	(0.2)%
(4) Revenues (Millions; $2002)	$11,894	$11,875	($19)	(0.2)%
(5) Costs (Millions; $2002)	$7,085	$7,103	$18	0.3%
(5a) Fuel Cost	$3,482	$3,463	($19)	(0.6)%
(5b) Variable O&M	$596	$595	($1)	(0.1)%
(5c) Fixed O&M	$2,123	$2,161	$39	1.8%
(5d) Capital Cost	$884	$884	($1)	(0.1)%
(6) Pre-Tax Income (Millions; $2002)	$4,809	$4,772	($37)	(0.8)%
(7) Variable Production Costs ($/MWh)	$13.61	$13.57	($0.04)	(0.3)%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	63,946	63,909	(38)	(0.1)%
(1a) Existing	53,659	53,166	(493)	(0.9)%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(1b) New Additions	10,288	10,743	455	4.4%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	3,083	3,576	493	16.0%
(2a) Energy Prices ($2002/MWh)	$23.96	$23.95	($0.01)	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$54.16	$54.80	$0.64	1.2%
(3) Generation (GWh)	303,096	302,009	(1,087)	(0.4)%
(4) Revenues (Millions; $2002)	$10,721	$10,729	$8	0.1%
(5) Costs (Millions; $2002)	$6,568	$6,570	$2	0.0%
(5a) Fuel Cost	$3,196	$3,213	$18	0.6%
(5b) Variable O&M	$627	$625	($2)	(0.3)%
(5c) Fixed O&M	$1,994	$1,977	($18)	(0.9)%
(5d) Capital Cost	$751	$755	$4	0.5%
(6) Pre-Tax Income (Millions; $2002)	$4,153	$4,159	$6	0.1%
(7) Variable Production Costs ($/MWh)	$12.61	$12.71	$0.10	0.8%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	38,477	38,477	0	0.0%
(1a) Existing	32,672	32,672	0	0.0%
(1b) New Additions	5,806	5,806	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	476	476	0	0.0%
(2a) Energy Prices ($2002/MWh)	$22.94	$22.77	($0.17)	(0.7)%
(2b) Capacity Prices ($2002/KW/yr)	$53.64	$54.88	$1.24	2.3%
(3) Generation (GWh)	195,033	195,262	229	0.1%
(4) Revenues (Millions; $2002)	$6,512	$6,532	$19	0.3%
(5) Costs (Millions; $2002)	$3,894	$3,915	$20	0.5%
(5a) Fuel Cost	$1,963	$1,962	($1)	0.0%
(5b) Variable O&M	$398	$398	$1	0.2%
(5c) Fixed O&M	$1,044	$1,060	$16	1.5%
(5d) Capital Cost	$490	$494	$5	0.9%
(6) Pre-Tax Income (Millions; $2002)	$2,618	$2,617	($1)	0.0%
(7) Variable Production Costs ($/MWh)	$12.10	$12.09	($0.01)	(0.1)%
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	76,114	76,154	40	0.1%
(1a) Existing	59,678	59,691	13	0.0%
(1b) New Additions	5,882	5,935	53	0.9%
(1c) Repowering Additions	10,554	10,528	(25)	(0.2)%
(1d) Closures	4,107	4,107	0	0.0%
(2a) Energy Prices ($2002/MWh)	$30.65	$30.67	$0.02	0.1%
(2b) Capacity Prices ($2002/KW/yr)	$48.65	$48.42	($0.23)	(0.5)%
(3) Generation (GWh)	302,155	302,422	267	0.1%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	AEO Base Case	Final Rule	Difference	% Change
(4) Revenues (Millions; $2002)	$12,689	$12,688	($2)	0.0%
(5) Costs (Millions; $2002)	$8,761	$8,822	$61	0.7%
(5a) Fuel Cost	$5,116	$5,110	($6)	(0.1)%
(5b) Variable O&M	$402	$400	($2)	(0.6)%
(5c) Fixed O&M	$1,831	$1,895	$64	3.5%
(5d) Capital Cost	$1,412	$1,417	$5	0.3%
(6) Pre-Tax Income (Millions; $2002)	$3,928	$3,865	($62)	(1.6)%
(7) Variable Production Costs ($/MWh)	$18.26	$18.22	($0.04)	(0.2)%
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	207,945	208,286	341	0.2%
(1a) Existing	164,552	164,552	0	0.0%
(1b) New Additions	43,393	43,734	341	0.8%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$25.81	$25.81	$0.00	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$47.48	$47.50	$0.03	0.1%
(3) Generation (GWh)	1,012,116	1,013,119	1,002	0.1%
(4) Revenues (Millions; $2002)	$35,984	$36,031	$48	0.1%
(5) Costs (Millions; $2002)	$22,345	$22,457	$112	0.5%
(5a) Fuel Cost	$11,804	$11,792	($12)	(0.1)%
(5b) Variable O&M	$1,870	$1,876	$6	0.3%
(5c) Fixed O&M	$5,411	$5,492	$81	1.5%
(5d) Capital Cost	$3,260	$3,297	$37	1.1%
(6) Pre-Tax Income (Millions; $2002)	$13,638	$13,574	($64)	(0.5)%
(7) Variable Production Costs ($/MWh)	$13.51	$13.49	($0.02)	(0.1)%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	52,670	52,644	(26)	0.0%
(1a) Existing	48,956	48,956	0	0.0%
(1b) New Additions	3,714	3,688	(26)	(0.7)%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$24.92	$24.98	$0.06	0.2%
(2b) Capacity Prices ($2002/KW/yr)	$45.59	$45.20	($0.39)	(0.8)%
(3) Generation (GWh)	233,472	233,542	70	0.0%
(4) Revenues (Millions; $2002)	$8,216	$8,209	($7)	(0.1)%
(5) Costs (Millions; $2002)	$4,742	$4,751	$9	0.2%
(5a) Fuel Cost	$2,944	$2,943	($1)	0.0%
(5b) Variable O&M	$430	$431	$1	0.2%
(5c) Fixed O&M	$1,076	$1,088	$12	1.1%
(5d) Capital Cost	$292	$289	($3)	(1.0)%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(6) Pre-Tax Income (Millions; $2002)	$3,474	$3,458	($16)	(0.5)%
(7) Variable Production Costs ($/MWh)	$14.45	$14.45	($0.01)	0.0%
Western Systems Coordinating Council (WSCC)				
(1) Total Domestic Capacity (MW)	177,780	177,780	0	0.0%
(1a) Existing	152,891	152,868	(23)	0.0%
(1b) New Additions	17,337	17,314	(24)	(0.1)%
(1c) Repowering Additions	7,552	7,599	47	0.6%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$27.65	$27.66	$0.01	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$25.05	$24.99	($0.06)	(0.2)%
(3) Generation (GWh)	806,830	806,834	4	0.0%
(4) Revenues (Millions; $2002)	$26,393	$26,384	($9)	0.0%
(5) Costs (Millions; $2002)	$16,417	$16,451	$34	0.2%
(5a) Fuel Cost	$8,772	$8,771	($1)	0.0%
(5b) Variable O&M	$1,226	$1,227	$1	0.1%
(5c) Fixed O&M	$4,327	$4,360	$33	0.8%
(5d) Capital Cost	$2,091	$2,093	$1	0.1%
(6) Pre-Tax Income (Millions; $2002)	$9,976	$9,933	($43)	(0.4)%
(7) Variable Production Costs ($/MWh)	$12.39	$12.39	$0.00	0.0%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (AEO electricity demand assumptions).

Table B2-A-2 repeats some of the information presented in Tables B3-4 and B3-A-1 to facilitate a comparison of the results using the two different electricity demand assumptions. The columns labeled "EPA" represent the results based on EPA electricity demand assumptions; the columns labeled"AEO" represent the results based on AEO electricity demand assumptions. The table highlights differences between the two cases of greater than or equal to 0.5 percent with bold font and pale blue shading. For a description of the metrics presented in this table, please refer to section B3-3.1.

Table B3-A-2: Comparison of Market-Level Impacts of the Final Rule (2010)													
NERC Region	Baseline Capacity (MW)		Incremental Capacity Closures (MW)		Closures as % of Baseline Capacity		Change in Variable Production Cost per MWh		Change in Energy Price per MWh		Change in Pre-Tax Income	
	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO
ECAR	118,529	127,332	0	0	0.0%	0.0%	0.1%	0.2%	0.3%	0.0%	(0.8)%	(0.8)%
ERCOT	75,290	80,472	0	0	0.0%	0.0%	0.0%	(0.1)%	**5.8%**	**1.3%**	**(5.6)%**	**(1.7)%**
FRCC	50,324	53,831	0	0	0.0%	0.0%	0.4%	0.2%	0.6%	0.5%	(3.0)%	(2.9)%
MAAC	63,784	68,838	0	0	0.0%	0.0%	**0.4%**	**(0.3)%**	0.1%	0.1%	(0.9)%	(0.8)%
MAIN	59,494	63,946	**94**	**493**	**0.2%**	**0.8%**	**0.1%**	**0.8%**	(0.3)%	0.0%	(0.3)%	0.1%
MAPP	35,835	38,477	0	0	0.0%	0.0%	(0.1)%	(0.1)%	(0.3)%	(0.7)%	0.1%	0.0%
NPCC	72,477	76,114	0	0	0.0%	0.0%	(0.5)%	(0.2)%	(0.1)%	0.1%	(1.9)%	(1.6)%
SERC	194,485	207,945	0	0	0.0%	0.0%	0.0%	(0.1)%	(0.1)%	0.0%	(0.5)%	(0.5)%
SPP	49,948	52,670	0	0	0.0%	0.0%	(0.1)%	0.0%	(0.2)%	0.2%	(0.4)%	(0.5)%
WSCC	167,748	177,780	58	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.5)%	(0.4)%
Total	**887,915**	**947,406**	**152**	**493**	**0.0%**	**0.1%**	**0.0%**	**0.0%**	**n/a**	**n/a**	**(1.0)%**	**(0.7)%**

Source: *IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA and AEO electricity demand assumptions).*

The comparison of the two market-level analyses of the final rule, using the two different electricity demand assumptions, shows only minor differences in the results. It should also be noted that the direction of the differences is not systematic, i.e., in some cases, impacts are greater under the AEO assumptions; in other cases, impacts are greater under the EPA assumptions.

- **Incremental capacity closures** are 341 MW higher under the AEO assumptions than under the EPA assumptions. This corresponds to less than 0.04 percent of total baseline capacity under either base case. **MAIN** is estimated to experience 493 MW of capacity closure under the AEO assumptions, compared to 94 under the EPA assumptions. Conversely, **WSCC** is estimated to experience 58 MW of capacity closure under the EPA assumptions and no closures under the AEO assumptions.

- MAIN is the only region with a difference in **incremental closures as a percentage of baseline capacity** under the two assumptions: under the AEO assumptions closures are approximately 0.6 percent higher than under the EPA assumptions.

- **Variable production costs per MWh** in MAAC increase by 0.4 percent under the EPA assumptions and fall by 0.3 percent under the AEO assumptions, a difference of 0.7 percentage points. Conversely, in MAIN, variable production cost per MWh increase more under the AEO assumptions than under the EPA assumptions (0.8 compared to 0.1 percent).

- **Energy price** increases in ERCOT are smaller under the AEO assumptions than under the EPA assumptions (1.3 percent compared to 5.8 percent, a difference of 4.5 percentage points).

- In ERCOT, facilities experience a much larger reduction in **pre-tax income** under the EPA assumptions than under the AEO assumptions (5.6 percent compared to 1.7 percent, a difference of 3.9 percentage points).

- **For all other measures and regions, the results under the two different electricity demand assumptions are within 0.5 percent of each other.**

B3-A.1-2 Analysis of Phase II Facilities for 2010 – AEO Assumptions

This section presents the results of the IPM analysis for the Phase II facilities that are modeled by the IPM. Eight of the 535 Phase II facilities are closures in the base case and under the final rule. These facilities are not represented in the results described in this section.

EPA used the IPM results from model run year 2010 to analyze impacts on Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the in-scope Phase II facilities as a group and (2) potential changes to individual facilities within the group of in-scope Phase II facilities.

a. In-scope Phase II facilities as a group

The analysis of the in-scope Phase II facilities as a group is largely similar to the market-level analysis, except that the base case and policy option totals only include the economic activities of the 535 in-scope Phase II facilities represented by the IPM. Table B3-A-3 below (equivalent to Table B3-5) presents six impact measures for the group of Phase II facilities: (1) capacity changes, including changes in the number and capacity of closure facilities; (2) generation changes; (3) revenue changes; (4) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (5) changes in pre-tax income; and (6) changes in variable production costs per MWh of generation, where variable production cost is defined as the sum of fuel cost and variable O&M cost. For each measure, the table presents the results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference.

Table B3-A-3: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	AEO Base Case	Final Rule	Difference	% Change
National Totals				
(1) Total Domestic Capacity (MW)	438,510	438,004	(506)	(0.1)%
(1a) Closures - Number of Facilities	8	8	0	0.0%
(1b) Closures - Capacity (MW)	10,204	10,697	493	4.8%
(2) Generation (GWh)	2,359,403	2,351,936	(7,466)	(0.3)%
(3) Revenues (Millions; $2002)	$81,220	$80,964	($256)	(0.3)%
(4) Costs (Millions; $2002)	$49,368	$49,544	$175	0.4%
(4a) Fuel Cost	$25,612	$25,465	($147)	(0.6)%
(4b) Variable O&M	$5,250	$5,245	($5)	(0.1)%
(4c) Fixed O&M	$15,612	$15,977	$365	2.3%
(4d) Capital Cost	$2,895	$2,857	($38)	(1.3)%
(5) Pre-Tax Income (Millions; $2002)	$31,851	$31,420	($431)	(1.4)%
(6) Variable Production Costs ($2002/MWh)	$13.08	$13.06	($0.02)	(0.2)%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	82,281	82,292	10	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	1	1	0	0.0%
(2) Generation (GWh)	532,207	532,268	61	0.0%
(3) Revenues (Millions; $2002)	$17,524	$17,530	$6	0.0%
(4) Costs (Millions; $2002)	$9,924	$10,018	$94	1.0%
(4a) Fuel Cost	$5,207	$5,221	$15	0.3%
(4b) Variable O&M	$1,302	$1,301	($1)	(0.1)%
(4c) Fixed O&M	$2,981	$3,074	$93	3.1%
(4d) Capital Cost	$434	$421	($12)	(2.9)%
(5) Pre-Tax Income (Millions; $2002)	$7,600	$7,512	($88)	(1.2)%

Table B3-A-3: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(6) Variable Production Costs ($2002/MWh)	$12.23	$12.25	$0.02	0.2%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	44,413	44,452	39	0.1%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	160,614	159,032	(1,582)	(1.0)%
(3) Revenues (Millions; $2002)	$5,919	$5,842	($76)	(1.3)%
(4) Costs (Millions; $2002)	$4,026	$4,009	($17)	(0.4)%
(4a) Fuel Cost	$2,186	$2,137	($49)	(2.2)%
(4b) Variable O&M	$421	$417	($3)	(0.8)%
(4c) Fixed O&M	$1,193	$1,218	$25	2.1%
(4d) Capital Cost	$227	$237	$10	4.3%
(5) Pre-Tax Income (Millions; $2002)	$1,892	$1,833	($59)	(3.1)%
(6) Variable Production Costs ($2002/MWh)	$16.23	$16.06	($0.17)	(1.0)%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	27,513	27,514	2	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	812	812	0	0.0%
(2) Generation (GWh)	80,925	80,927	3	0.0%
(3) Revenues (Millions; $2002)	$3,445	$3,431	($14)	(0.4)%
(4) Costs (Millions; $2002)	$2,002	$2,045	$43	2.2%
(4a) Fuel Cost	$1,093	$1,101	$8	0.7%
(4b) Variable O&M	$197	$200	$3	1.6%
(4c) Fixed O&M	$682	$716	$34	5.0%
(4d) Capital Cost	$30	$28	($2)	(5.6)%
(5) Pre-Tax Income (Millions; $2002)	$1,443	$1,386	($57)	(4.0)%
(6) Variable Production Costs ($2002/MWh)	$15.94	$16.07	$0.13	0.8%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	35,482	35,482	0	0.0%
(1a) Closures - Number of Facilities	1	1	0	0.0%
(1b) Closures - Capacity (MW)	1,725	1,725	0	0.0%
(2) Generation (GWh)	182,096	181,226	(870)	(0.5)%
(3) Revenues (Millions; $2002)	$6,846	$6,825	($21)	(0.3)%
(4) Costs (Millions; $2002)	$3,894	$3,907	$13	0.3%
(4a) Fuel Cost	$1,766	$1,741	($25)	(1.4)%
(4b) Variable O&M	$375	$374	($1)	(0.3)%
(4c) Fixed O&M	$1,587	$1,626	$38	2.4%
(4d) Capital Cost	$166	$166	$0	0.0%
(5) Pre-Tax Income (Millions; $2002)	$2,952	$2,918	($34)	(1.1)%

Table B3-A-3: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(6) Variable Production Costs ($2002/MWh)	$11.76	$11.67	($0.09)	(0.7)%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	38,606	38,113	(493)	(1.3)%
(1a) Closures - Number of Facilities	2	2	0	0.0%
(1b) Closures - Capacity (MW)	3,083	3,576	493	16.0%
(2) Generation (GWh)	239,552	236,989	(2,563)	(1.1)%
(3) Revenues (Millions; $2002)	$7,705	$7,639	($66)	(0.9)%
(4) Costs (Millions; $2002)	$4,589	$4,529	($60)	(1.3)%
(4a) Fuel Cost	$2,185	$2,174	($11)	(0.5)%
(4b) Variable O&M	$540	$537	($4)	(0.6)%
(4c) Fixed O&M	$1,732	$1,709	($23)	(1.3)%
(4d) Capital Cost	$132	$109	($23)	(17.4)%
(5) Pre-Tax Income (Millions; $2002)	$3,116	$3,110	($6)	(0.2)%
(6) Variable Production Costs ($2002/MWh)	$11.37	$11.44	$0.06	0.6%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	15,749	15,749	0	0.0%
(1a) Closures - Number of Facilities	1	1	0	0.0%
(1b) Closures - Capacity (MW)	476	476	0	0.0%
(2) Generation (GWh)	110,585	110,668	83	0.1%
(3) Revenues (Millions; $2002)	$3,323	$3,327	$4	0.1%
(4) Costs (Millions; $2002)	$2,004	$2,020	$16	0.8%
(4a) Fuel Cost	$1,067	$1,068	$1	0.1%
(4b) Variable O&M	$226	$227	$0	0.2%
(4c) Fixed O&M	$597	$612	$15	2.4%
(4d) Capital Cost	$114	$114	$0	0.0%
(5) Pre-Tax Income (Millions; $2002)	$1,319	$1,307	($12)	(0.9)%
(6) Variable Production Costs ($2002/MWh)	$11.70	$11.70	$0.01	0.0%
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	37,219	37,164	(55)	(0.1)%
(1a) Closures - Number of Facilities	4	4	0	0.0%
(1b) Closures - Capacity (MW)	4,107	4,107	0	0.0%
(2) Generation (GWh)	159,374	157,749	(1,626)	(1.0)%
(3) Revenues (Millions; $2002)	$6,594	$6,532	($63)	(1.0)%
(4) Costs (Millions; $2002)	$4,948	$4,953	$5	0.1%
(4a) Fuel Cost	$2,667	$2,621	($46)	(1.7)%
(4b) Variable O&M	$268	$264	($4)	(1.6)%
(4c) Fixed O&M	$1,238	$1,302	$63	5.1%
(4d) Capital Cost	$774	$766	($8)	(1.1)%
(5) Pre-Tax Income (Millions; $2002)	$1,646	$1,579	($67)	(4.1)%
(6) Variable Production Costs ($2002/MWh)	$18.42	$18.29	($0.13)	(0.7)%

Table B3-A-3: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	107,458	107,458	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	641,200	641,238	39	0.0%
(3) Revenues (Millions; $2002)	$21,403	$21,410	$7	0.0%
(4) Costs (Millions; $2002)	$12,103	$12,168	$65	0.5%
(4a) Fuel Cost	$6,200	$6,186	($13)	(0.2)%
(4b) Variable O&M	$1,370	$1,375	$5	0.4%
(4c) Fixed O&M	$3,983	$4,057	$73	1.8%
(4d) Capital Cost	$549	$550	$0	0.0%
(5) Pre-Tax Income (Millions; $2002)	$9,300	$9,242	($58)	(0.6)%
(6) Variable Production Costs ($2002/MWh)	$11.81	$11.79	($0.01)	(0.1)%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	20,471	20,471	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	109,277	108,596	(681)	(0.6)%
(3) Revenues (Millions; $2002)	$3,558	$3,537	($21)	(0.6)%
(4) Costs (Millions; $2002)	$1,941	$1,934	($7)	(0.4)%
(4a) Fuel Cost	$1,138	$1,120	($18)	(1.6)%
(4b) Variable O&M	$241	$241	($1)	(0.3)%
(4c) Fixed O&M	$557	$569	$13	2.3%
(4d) Capital Cost	$5	$4	($1)	(20.7)%
(5) Pre-Tax Income (Millions; $2002)	$1,617	$1,603	($14)	(0.9)%
(6) Variable Production Costs ($2002/Mwh)	$12.63	$12.53	($0.10)	(0.8)%
Western Systems Coordinating Council (WSCC)				
(1) Total Domestic Capacity (MW)	29,318	29,309	(8)	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	143,572	143,242	(331)	(0.2)%
(3) Revenues (Millions; $2002)	$4,902	$4,891	($11)	(0.2)%
(4) Costs (Millions; $2002)	$3,937	$3,961	$24	0.6%
(4a) Fuel Cost	$2,104	$2,096	($9)	(0.4)%
(4b) Variable O&M	$309	$310	$1	0.2%
(4c) Fixed O&M	$1,061	$1,094	$33	3.1%
(4d) Capital Cost	$464	$463	($1)	(0.3)%
(5) Pre-Tax Income (Millions; $2002)	$964	$929	($35)	(3.6)%
(6) Variable Production Costs ($2002/MWh)	$16.81	$16.79	($0.02)	(0.1)%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (AEO electricity demand assumptions).

Table B3-A-4 repeats some of the information presented in Tables B3-5 and B3-A-3 to facilitate a comparison of the results using the two different electricity demand assumptions. The columns labeled "EPA" represent the results based on EPA electricity demand assumptions; the columns labeled"AEO" represent the results based on AEO electricity demand assumptions. The table highlights differences between the two cases of greater than or equal to 0.5 percent with bold font and pale blue shading For a description of the metrics presented in this table, please refer to section B3-3.2.

Table B3-A-4: Comparison of Facility-Level Impacts of the Final Rule (2010)

NERC Region	Baseline Capacity (MW)		Incremental Capacity Closures (MW)		Closures as % of Baseline Capacity		Change in Variable Production Cost per MWh		Change in Generation		Change in Pre-Tax Income	
	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO
ECAR	82,313	82,281	0	0	0.0%	0.0%	0.0%	0.2%	(0.2)%	0.0%	(1.0)%	(1.2)%
ERCOT	43,522	44,413	0	0	0.0%	0.0%	(0.7)%	(1.0)%	**(1.8)%**	**(1.0)%**	**(10.4)%**	**(3.1)%**
FRCC	27,537	27,513	0	0	0.0%	0.0%	**0.3%**	**0.8%**	**(0.8)%**	**0.0%**	(4.0)%	(4.0)%
MAAC	34,376	35,482	0	0	0.0%	0.0%	**0.0%**	**(0.7)%**	**0.2%**	**(0.5)%**	(1.4)%	(1.1)%
MAIN	36,498	38,606	**94**	**493**	**0.3%**	**1.3%**	**0.1%**	**0.6%**	**(0.3)%**	**(1.1)%**	(0.6)%	(0.2)%
MAPP	15,749	15,749	0	0	0.0%	0.0%	(0.1)%	0.0%	0.0%	0.1%	**(0.3)%**	**(0.9)%**
NPCC	37,651	37,219	0	0	0.0%	0.0%	**(1.7)%**	**(0.7)%**	**(3.6)%**	**(1.0)%**	(4.3)%	(4.1)%
SERC	107,450	107,458	0	0	0.0%	0.0%	(0.3)%	(0.1)%	(0.2)%	0.0%	(0.7)%	(0.6)%
SPP	20,471	20,471	0	0	0.0%	0.0%	(0.4)%	(0.8)%	(0.7)%	(0.6)%	(1.0)%	(0.9)%
WSCC	28,431	29,318	58	0	0.2%	0.0%	**(0.9)%**	**(0.1)%**	**(4.3)%**	**(0.2)%**	**(10.4)%**	**(3.6)%**
Total	**433,998**	**438,510**	**152**	**493**	**0.0%**	**0.1%**	**(0.6)%**	**(0.2)%**	**(0.8)%**	**(0.3)%**	**(1.8)%**	**(1.4)%**

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA and AEO electricity demand assumptions).

The comparison of the final rule using the two different electricity demand assumptions show the differences listed below. It should be noted that the direction of the differences is not systematic, i.e., in some cases, impacts are greater under the AEO assumptions; in other cases, impacts are greater under the EPA assumptions.

- **Incremental capacity closures** are 341 MW higher under the AEO assumptions than under the EPA assumptions. This corresponds to less than 0.08 percent of Phase II capacity under either base case. The incremental capacity closure results are identical to the market-level results discussed above.

- **Closures as a percentage of baseline capacity** in MAIN are 1.0 percent higher under the AEO assumptions than under the EPA assumptions.

- **The change in variable production cost per MWh** differs by 0.5 percent or more in five NERC regions: in FRCC and MAIN, it increases more under the AEO assumptions than under EPA assumptions; in MAAC, it decreases under AEO assumptions but is unchanged under the EPA assumptions; and in NPPC and WSCC, it decreases less under the AEO assumptions than under the EPA assumptions.

- **The change in generation** differs by 0.5 percent or more in six NERC regions: in ERCOT, FRCC, NPCC, and WSCC, Phase II facilities lose more generation under the EPA assumptions than under the AEO assumptions; in MAIN, they lose more generation under the AEO assumptions than under the EPA assumptions; and in MAAC they experience an increase in generation under the EPA assumptions and a decrease under the AEO assumptions.

- **The change in pre-tax income** differs by 0.5 percent or more in three NERC regions: in MAPP, Phase II facilities experience a slightly higher reduction in pre-tax income under the AEO assumptions than under the EPA assumptions (0.9 percent compared to 0.3 percent). In WSCC and ERCOT, however, the reduction in pre-tax income is substantially higher under the EPA assumptions than under the AEO assumptions (over 10 percent compared to less than 4 percent).

- **For all other measures and regions, the results under the two different electricity demand assumptions are within 0.5 percent of each other.**

b. Individual Phase II facilities

In addition to effects of the final rule on the in-scope Phase II facilities as a group, there may be shifts in economic performance among individual facilities subject to Phase II regulation. To assess such potential shifts, EPA analyzed facility-specific changes in (1) capacity utilization (defined as generation divided by capacity multiplied by the number of hours per year – 8,760); (2) generation; (3) revenues; (4) variable production costs per MWh of generation (defined as variable O&M cost plus fuel cost divided by generation); (5) fuel cost per MWh of generation; and (6) pre-tax income. For each measure, EPA determined the number of Phase II facilities that experience no changes, or an increase or a reduction within three ranges: 1 percent or less, 1 to 3 percent, and more than 3 percent.

Table B3-A-5 (equivalent to Table B3-6) presents the total number of Phase II facilities with different degrees of change in each of these measures. This table excludes 17 facilities with significant status changes including (eight facilities are baseline closures and nine facilities changed their repowering decisions between the base case and policy case). These facilities are either not operating at all in the base case or the post-compliance case, or they experience fundamental changes in the type of units they operate; therefore, the measures presented below would not be meaningful for these facilities. In addition, the changes in production cost per MWh and fuel cost per MWh could not be developed for 58 facilities with zero generation in either the base case or post-compliance scenario. For these facilities, the change in production cost per MWh and fuel cost per MWh is indicated as "n/a."

Table B3-A-5: Number of Individual Phase II Facilities with Operational Changes (2010)

Economic Measures	Reduction			Increase			No Change	N/A
	</= 1%	1-3%	> 3%	</= 1%	1-3%	> 3%		
(1) Change in Capacity Utilization	6	14	17	9	9	7	456	0
(2) Change in Generation	3	5	32	8	6	15	449	0
(3) Change in Revenues	46	26	36	115	14	14	267	0
(4) Change in Variable Production Costs/MWh	38	10	9	136	13	13	241	58
(5) Change in Fuel Costs	47	6	9	35	13	8	342	58
(6) Change in Pre-Tax Income	139	114	195	28	7	9	26	0

[a] For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.
[b] The change in capacity utilization is the difference between the capacity utilization percentages in the base case and post-compliance case. For all other measures, the change is expressed as the percentage change between the base case and post-compliance values.

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (AEO electricity demand assumptions).

Table B3-A-5 indicates that the majority of Phase II facilities will not experience changes in capacity utilization, generation, or fuel costs per MWh due to compliance with the final rule. Of those facilities with changes in post-compliance capacity utilization and generation, most will experience decreases in these measures. The majority of facilities with changes in post-compliance variable production costs per MWh will experience increases. However, more than 80 percent of those increases will not exceed 1.0 percent. Changes in revenues at most Phase II facilities will also not exceed 1.0 percent. The largest effect of the final rule will be on facilities' pre-tax income: over 85 percent of facilities will experience a reduction in pre-tax income, with about 40 percent experiencing a reduction of 3.0 percent or greater. These reductions are due to a combination of reduced revenues and increased compliance costs.

Chapter B3 - Appendix B

INTRODUCTION

This appendix presents additional, more detailed information on EPA's research to identify models suitable for analysis of environmental policies that affect the electric power industry.

CHAPTER CONTENTS

B3-B.1 SUMMARY COMPARISON OF ENERGY MARKET MODELS

EPA performed research to identify electricity market models that could potentially be used in the analysis of impacts associated with regulatory options considered for section 316(b) Phase II regulation. This research included reviewing available forecast studies and interviewing persons knowledgeable in the area of electricity market forecasting. EPA focused on identifying models that are widely used for public policy analyses, peer reviewed, of national scope, and have the capabilities needed to perform regulatory impact scenario analyses of the type required for the section 316(b) Phase II economic analyses. Based on this research, EPA identified three models that were potentially suitable for the analysis of the section 316(b) Phase II regulations:

- (1) The Department of Energy's National Energy Modeling System (NEMS),
- (2) The Department of Energy's The Policy Office Electricity Modeling System (POEMS), and
- (3) ICF Consulting's Integrated Planning Model (IPM®).

Each of these models was developed to meet the specific needs of different end users and therefore differ in terms of structure, inputs, outputs, and capability. Table B3-A-1 below presents a detailed comparison of the three models. The comparison comprises:

- ***General features,*** including a description of each model, their general applications, and their environmental applications.

- ***Modeling features,*** including each model's treatment of existing environmental regulations, of industry restructuring, and of economic plant retirements; their regional capabilities; their plant/unit detail and data sources; their general data inputs and outputs; and their data inputs and outputs required for the section 316(b) analysis.

- ***Logistical considerations,*** including each model's costs, computational requirements, accessability and response time; their documentation and issues regarding disclosure of inputs or results; and general notes and references.

Table B3-B-1: Comparison of Electricity Market Models			
Model	**DOE/EIA: NEMS**	**DOE/OP: POEMS (OnLocation, Inc.)**	**EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)**
	General Features		
Description	Modular structured model of national energy supply and demand, includes macroeconomic, international, supply and demand modules, as well as an electricity market module (EMM) that can be run independently. The EMM represents generation, transmission and prices of electricity. Based on forecasts of fuel prices, variable O&M, and electricity demand, determines plant dispatch to ***achieve the least cost supply of electric power***.	POEMS is a model integration system that allows the substitution of the TRADELEC model for the EMM in NEMS. TRADELEC allows for a greater level of detail about the electricity sector than the EMM. Designed to examine the effect of market structure transformation of the electricity sector. It solves for the trade of the commodity as a function of relative prices, transmission constraints and cost of market entry by ***maximizing economic gains*** achieved through commodity trading.	A production cost model based on linear programming approach, solves for least cost dispatch. Simulates system dispatch and operations, estimates marginal generation costs on an hourly basis. ***Minimizes present worth of total system cost*** subject to various constraints.
General Applications	Used to produce annual forecasts of energy supply, demand, and prices through 2020 for the Annual Energy Outlook. Can also be used to analyze effects of regulations. EIA performs studies for Congress, DOE, other agencies.	Used by DOE's policy office to study the impacts of electricity market transformation/ deregulation through 2010. Supports the administration's 1999 bill on industry deregulation, the Comprehensive Electricity Competition Act (CECA).	Primary model used by EPA Air Program offices to evaluate policy and regulatory impacts through 2030. EPA Office of Policy also used this model for GCC and retail deregulation analysis. Used by over 50 private sector clients to develop compliance plans, price forecasts, market analysis, and asset valuation.
Environmental Applications	Includes a Carbon Emission submodule. Can also calculate emissions. Produced "Analysis of Carbon Mitigation Cases" for EPA.	DOE application generally not designed to perform environmental regulatory analysis. Examines a renewable portfolio standard. EPA/ARD concluded that air emission estimates are low relative to IPM and other models. However, DOE contractor has performed analyses of environmental policies for private clients.	Analyzes environmental regulations by simultaneously selecting optimal compliance strategies for all generating units. Can calculate emissions, and simulate trading scenarios. Used for ozone (NO_x), SO_2, and mercury emissions control scenarios; implementation of NAAQS for ozone and PM; alternative NO_x emissions trading and rate-based programs for OTAG, CAA Title IV NO_x Rule; NO_x control options; RIA for the NO_x SIP call; and GCC scenarios. Possible to accommodate other environmental regulations.

Table B3-B-1: Comparison of Electricity Market Models			
Model	**DOE/EIA: NEMS**	**DOE/OP: POEMS (OnLocation, Inc.)**	**EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)**
	Modeling Features		
Treatment of Environmental Regulations	Reference case represents all existing regulations and legislation in effect as of July 1, 1998, including impacts of the Climate Change Action Plan and the NO_x SIP call. EMM can analyze seasonal environmental controls to the extent that they match up with the seasonal representations in the model (non-sequential months are grouped according to similar load characteristics).	Assumes existing regulations and legislation remain in place and facilities comply with existing regulations in the least cost way. Most recent reference case analysis includes NO_x SIP call. Assesses a renewable portfolio in the competition case. Does not include other proposed or anticipated environmental regulatory scenarios in DOE analysis.	The base case includes current federal and state air quality requirements, including future implementation of SO_2 and NO_x requirements of Title IV of the CAA, the NO_x SIP call as implemented through a cap and trade program. Base case also includes assumptions regarding demand reductions associated with the Climate Change Action Plan.
Treatment of Restructuring	All regions assumed to have wholesale competition. Only states with enacted legislation are treated as competitive for retail markets in base case. Has a competitive pricing scenario that assumes full retail competition.	Designed to compare competitive wholesale and cost-of-service retail market structures to fully competitive market structure at the wholesale and retail levels. Compares prices and determines "stranded assets" at the firm level. Pricing modeled for 114 power control areas, assumes profit maximizing behavior.	EPA uses assumptions in IPM that reflect wholesale competition occurring throughout the electric power industry. Work for private clients uses different assumptions.
Treatment of Economic Plant Retirements	Uses assumptions about licencing and needs for new major capital expenses to forecast nuclear retirements. For fossil steam, model checks yearly to compare revenues at market price with future O&M and fuel costs to forecast economic retirements. Results appear to have second highest forecast of fossil steam retirements compared to other models.	Uses same method as NEMS for forecasting "forced" retirements of nuclear assets due to operating constraints such as licences. Economic retirements based on lack of ability to cover short term going forward costs and the cost of capacity replacement in the long term. Results appear to have highest forecast of fossil steam retirements compared to other models.	Uses assumptions about licencing in forecasting nuclear retirements. The IPM model retires capacity when unit level operating costs reach a level that total electric system costs are minimized by shutting down the existing unit.
Regional Capabilities	Model runs analysis for 15 supply regions.	Analyzes 114 power control areas connected by 680 transmission links.	Analyzes 26 supply regions that can be mapped to NERC regions.
Plant/Unit Detail	Groups all plants into 36 capacity types based on fuel type, burner technology, emission control technology, etc. within a region. Units or plants can be grouped differently according to §316(b) characteristics.	Units are grouped according to demand and supply regions, fuel type, prime mover, in-service period, similar heat rates. There are 6,000 unit groupings, an average of 55 per power control area. Plants can be re-grouped for §316(b).	Groups approximately 12,000 generating units into model plants. Grouped by region, state, technology, boiler configuration, location, fuel, heat rate, emission rate, pollution control, coal demand region. Plants can be re-grouped for §316(b).

Table B3-B-1: Comparison of Electricity Market Models			
Model	**DOE/EIA: NEMS**	**DOE/OP: POEMS (OnLocation, Inc.)**	**EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)**
	Modeling Features (cont.)		
Plant/Unit Data Sources	Form EIA-860A (all utility plants); Form EIA-867 (nonutility plants <1MW); Form EIA-767 (steam plants <10MW); Form EIA-759 (monthly operating data for utility plants).	Model includes "virtually all" currently existing generating units, including utility, exempt wholesale generators (EWGs), and cogenerators.	Over 12,000 generating units are represented in this model. Includes all utility units included in Form EIA-860 database. Plus IPPs and cogenerating units that sell firm power to the wholesale market. Also draws from other EIA Forms, Annual Energy Outlook (AEO), UDI, and other public and private databases. In addition, ICF has developed a database of industrial steam boilers with over 250 MMBtu/hr capacity in 22 eastern states.
General Data Inputs	Demand, financial data, tax assumptions, EIA and FERC data on capital costs, O&M costs, operating parameters, emission rates, existing facilities, new technologies, transmission constraints, and other inputs from other modules.	Inputs are similar to NEMS (for demand, fuel price and macroeconomic data), and EIA reports. FERC filings for other inputs such as capacity, operating costs, performance, transmission, imports, and financial parameters.	Some inputs are similar to NEMS, including demand forecast, and cost and performance of new and existing units. Emission constraints, repowering, and retrofit options are EPA specified. Fuel supply curves are used to model gas and coal prices.
Data Inputs for §316(b) EA	Would need to provide information on additional capital costs, O&M costs, study costs, outage period for technology installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each type of model plant***.	Would need to provide information on additional capital costs, O&M costs, outage period for installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each plant grouping***.	Would need to provide information on additional capital costs, O&M costs, outage period for installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each type of model plant***.
General Data Outputs	Retail price and price components, fuel demand, capital requirements, emissions, DSM options, capacity additions, and retirements by region and fuel type.	Dispatch, electricity trade, capacity expansion, retirements, emissions, and pricing (retail and wholesale) by region, state, and fuel type.	Regional and plant emissions; fuel, capital, and O&M costs; environmental retrofits; capacity builds; marginal energy costs; fuel supply, demand, and prices (primarily wholesale; one study focused on retail market).
Data Outputs for §316(b) EBA	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and fuel type***. EMM cannot provide results on a state-by-state basis. By design, it is not possible to map model plant results back to specific plant/owner using current modeling approach.	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and plant grouping***. Could map costs to units and owners with some modification of structure.	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and model plant type***. Currently has ability to map back to specific unit and plant/owner. While this process is automated, it requires 2-3 days of manual checking for every year modeled.

Table B3-B-1: Comparison of Electricity Market Models

Model	DOE/EIA: NEMS	DOE/OP: POEMS (OnLocation, Inc.)	EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)
	Logistical Considerations		
Costs *(cost estimates should be considered very preliminary)*	No out-of-pocket costs expected.	Initial policy case using existing scenario: \$15-20k. Setting up new base case scenario, performing several runs, and producing briefing: \$40-60k. (Assumes plant re-grouping cost is included in second estimate only.)	Initial policy case: \$20-30k. Incremental cases \$2-10k. Re-grouping model plants would be labor intensive and add costs to analysis.
Computational Requirements	Setting up a policy case may take two months. The model run time is two hours without iterating with rest of NEMS, four hours for total NEMS iteration. EIA runs NEMS on RS6000 workstations.	Setting up and running policy case could take from a few days to a few weeks, depending on whether policy case builds on an existing scenario and the complexity of the policy scenarios.	Depends on number of model plants and number of years in analysis. Base case approximately 4-6 hours.
Accessability and Response Time	Access and response time dependent on agreement between EIA and EPA and EIA's schedule. Could be difficult to get results turned around in time to meet regulatory schedule, depending on EIA's reporting schedule.	Access and response time potentially dependent on agreement between DOE and EPA and DOE's schedule. Model run by a contractor. ARD has impression that model has long set-up time, model not set up to perform many iterations quickly.	ICF is an EPA contractor. Assume that access and response time will be consistent with requirements of analysis.
Documentation and Disclosure of Inputs/Results	Documentation and results already available to public. Presented by year for fuel type and region. Could make aggregated results publicly available. EIA does not release plant-specific results.	Documentation and results of reference and competition cases are available to public on DOE's web page.	Documentation of the EPA Base Case already available to public. Assume disclosure would be similar to that for NO_x SIP call, etc. EPA/ARD states that there is more in public domain regarding IPM than most models.
Notes	The NEMS code and data are available to anyone for their own use. Anyone wishing to use NEMS is responsible for any code conversions or setup on their own systems. For example, FORTRAN compilers differ between the workstation and PC. Several national laboratories and consulting firms have used NEMS or portions of it, but the time investment is considerable. One out-of-pocket expense is the purchase of an Optimization Modeling Library (OML) license. OML is used to solve the embedded linear programs in NEMS. In order to modify or execute one of the NEMS modules that includes a linear program (EMM is one of them), an OML license is required.	DOE's contractor stated that they may need to make some structural changes to the modeling framework to accommodate the requirements for §316(b) analysis so that the model can incorporate the effects of the additional costs into the decision process (either to continue running a plant or to retire and replace the plant).	OAP sensitive to other EPA offices using another model or using IPM with different assumptions. Willing to coordinate and provide background and technical support. The EPA Base Case has received some challenges over impacts of Climate Change Action Plan on end-use demand. However, has cleared OMB review under other regulatory proposals.

Table B3-B-1: Comparison of Electricity Market Models

Model	DOE/EIA: NEMS	DOE/OP: POEMS (OnLocation, Inc.)	EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)
References	Annual Energy Outlook 1999, Report#:DOE/EIA-0383(99); Assumptions to the AEO99, Report#:DOE/EIA-0554(99); EMM/NEMS Model Documentation Report, Report#: DOE/EIA-M0689(99); Personal communications with EIA staff: Jeffrey Jones (jeffrey.jones@eia.doe.gov) and Susan Holte (sholte@eia.doe.gov).	POEMS Model Documentation, June 1998; Supporting Analysis for the Comprehensive Electricity Competition Act (CECA), May, 1999, Report#: DOE/PO-0059; The CECA: A Comparison of Model Results, September, 1999, Report#: SR/OAIF/99-04; Personal communications with DOE staff: John Conti (john.conti@hq.doe.gov), EPA staff: Sam Napolitano (napolitano.sam@epa.gov), and contractor: Lessly Goudarzi (goudarzi@onlocationinc.com).	Analyzing Electric Power Generation Under the CAA (Appendix 2), March, 1998 (EPA/OAR/ARD); Analysis of Emission Reduction Options for the Electric Power Industry (Chapter 2), March, 1999 (EPA/OAR/ARD); IPM Demonstration, May, 1998 (slides by ICF); Personal communications with EPA staff: Sam Napolitano (napolitano.sam@epa.gov), and contractors: John Blaney (blaneyj@icfkaiser.com).

Source: U.S. EPA analysis, 2002.

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